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October 29, 2004
L-04-141

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Subject: Beaver Valley Power Station, Unit No. 1 and No. 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Response to Request for Additional Information in Support of LAR Nos. 306 and 176 Emergency Diesel Generator Allowed Outage Time Extension

This letter provides the FirstEnergy Nuclear Operating Company (FENOC) response to an NRC request for additional information (RAI) dated September 24, 2004, relating to FENOC letter L-04-072 dated May 26, 2004.

FENOC letter L-04-072 submitted License Amendment Request (LAR) Nos. 306 and 176 for Beaver Valley Power Station (BVPS) Units No. 1 and 2, respectively. These amendment requests proposed changes to the BVPS Unit No. 1 and 2 Technical Specifications which would extend the current Emergency Diesel Generator (EDG) allowed outage time (AOT) to 14 days, remove the surveillance requirement for performing EDG maintenance inspections from the Technical Specifications, and revise the EDG Technical Specification requirements for restoring EDG fuel oil properties to within limits.

The FENOC response to the request for additional information is provided in Attachment A of this letter. Attachment B of this letter provides a discussion of the PRA model differences between BVPS Unit 1 and Unit 2 and their impacts on the EDG AOT Extension. Attachment C provides the BVPS EDG recovery methodology used in the PRA models. No new regulatory commitments are contained in this submittal.

This information does not change the evaluations or conclusions of the No Significant Hazards Consideration presented in FENOC letter L-04-072. If there are any questions concerning this matter, please contact Mr. Larry R. Freeland, Manager, Regulatory Compliance at 724-682-4284.

A001

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 29, 2004.

Sincerely,

L. W. Pearce

L. William Pearce

Attachments:

A. Responses to Request for Additional Information Related to BVPS-1 and 2 EDG AOT Extension
B. Key Differences in the BVPS PRA Models and Their Impact on the EDG AOT Extension
C. BVPS EDG Recovery Methodology

c: Mr. T. G. Colburn, NRR Senior Project Manager
Mr. P. C. Cataldo, NRC Sr. Resident Inspector
Mr. S. J. Collins, NRC Region I Administrator
Mr. D. A. Allard, Director BRP/DEP
Mr. L. E. Ryan (BRP/DEP)

Attachment A

Letter L-04-141

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION RELATED TO FIRSTENERGY NUCLEAR OPERATING COMPANY (FENOC) BEAVER VALLEY POWER STATION, UNIT NOS. 1 AND 2 (BVPS-1 AND 2) EMERGENCY DIESEL GENERATOR (EDG) ALLOWED OUTAGE TIME (AOT) DOCKET NOS. 50-334 AND 50-412

The NRC staff has requested the following additional information to complete its review of the FENOC license amendment application to extend the BVPS-1 and 2 EDG AOTs to 14 days:

1. Section 4.3.2 of the license amendment request (LAR) states that the BVPS-1 and 2 probabilistic risk assessment (PRA) models underwent a Westinghouse Owners' Group Peer Review in July 2002. Please provide the following information: (Regulatory Guide (RG) 1.174, Section 2.2.3; RG 1.177, Section 2.3.1)

   a. The LAR states that the Peer Review focused primarily on the Unit 2 PRA, but the Review Team was provided with Unit and PRA modeling differences. Please provide a summary of the differences between Unit 1 and 2, and the impact these differences have on the risk assessment of the proposed EDG AOT extension.

      Response:

      The PRA Peer Review team was presented with the PRA modeling differences between the BVPS Units during their review in July 2002. However, following the PRA peer review both the Unit 1 and Unit 2 PRA models have been updated, and incorporate the PRA Peer Review Category A and Category B findings and observations that were found to have an impact on the models. The Unit 1 PRA model was updated in September 2003 to Revision 3 (BV1REV3), and the Unit 2 PRA model was updated in May 2003 to Revision 3B (BV2REV3B). Attachment B lists the current major PRA modeling differences between the BVPS Units and their expected impact on the 14-day EDG AOT extension.

   b. The LAR states that seismic and fire risk are directly included with the internal events and internal flood initiators in the BVPS-1 and 2 PRA models. The Westinghouse Peer Review process utilizes NEI 00-02, which addresses at power, internal events PRAs. For seismic and fire risk, please describe your quality activities to ensure that the PRA is adequate for the present application in terms of scope, level of detail, and technical acceptability and provide a summary of any peer reviews, comparison studies, or similar evaluation of the seismic and fire modeling.

Response:

The quality activities that were performed for the BVPS seismic and fire PRA models are twofold. First, the seismic and fire PRA models were reviewed internally by both the utility personnel and the IPEEE contractors (PLG and Stevenson & Associates). Secondly, the NRC and their contractors (Brookhaven and Sandia National Laboratories) also reviewed the PRA models during the BVPS IPEEE submittal review, and found the results to be reasonable and capable of identifying the most likely severe accidents and vulnerabilities from external events.

Additionally, the seismic and fire PRA models are integrated with the internal events PRA models, so the plant response modeling (fault trees and event trees) following the external initiating events have been updated as part of the PRA model update process identified in the response to RAI question 1.a. During this update, the seismic PRA models were also revised to incorporate the uniform hazard spectrum (UHS) shape resolution of the NRC RAI on the IPEEE evaluation, dated July 8, 1998.

It should also be mentioned that the fire PRA model at Unit 2 identified a fire at the opposite train EDG as a major risk contributor to the 14-day EDG AOT sensitivity studies. Therefore, FENOC considers that the external events PRA models are adequate to fully address the seismic and fire risk associated with this risk-informed application.

2. FENOC provided a summary of the BVPS-2 Peer Review Findings and Observations (F&Os) in a previous letter (Pearce/USNRC, Beaver Valley Power Station, Unit No. 2, BV-2 Docket No. 50-412, License No. NPF-73, Response to a Request for Additional Information in Support of License Amendment Requests [sic] No. 180, dated October 24, 2003, Serial L-03-160). Please provide additional information related to the EDG AOT extension request as follows: (RG 1.174, Section 2.2.3; RG 1.177, Section 2.3.1)

   a. Corrective Action 02-09042-13 resolved an F&O involving comparative failure probabilities between EDGs and related circuit breakers. Please provide the original and updated failure probabilities for the affected component failure modes, for both BVPS-1 and 2 PRA models.

   Response:

   Corrective Action 02-09042-13 resolved a Peer Review F&O on the Unit 2 EDG failure probabilities. This error was due to overestimating the demands and run hours during the data update process for the period reviewed. In response to this corrective action and Corrective Action 02-09037-03, the success data (demands and hours of operation) for all Unit 2 components that used Bayesian updating of their failure rates were checked against the Maintenance Rule estimated success data, and were revised as needed if discrepancies were found. This process was also applied to the Unit 1 components. The review of Unit 1 success data was performed prior to the data update process, so the differences in the original and updated failure rates are due to Bayesian updating using actual plant data.

The following are the Unit 1 and Unit 2 failure rates associated with the EDGs for both the original (prior) and the updated (current) PRA models.

Unit 1

Original EDG Failure Rates (BV1REV2 PRA model)
ZTDGS1 = 6.0922E-03; EDG - failure during first hour

ZTDGS2 = 1.7774E-03; EDG - failure to run after first hour

ZTDGSS = 1.2669E-02; EDG - failure to start on demand

Updated EDG Failure Rates (BV1REV3 PRA model)
ZTDGS1 = 3.7780E-03; EDG - failure during first hour

ZTDGS2 = 1.1605E-03; EDG - failure to run after first hour

ZTDGSS = 9.9193E-03; EDG - failure to start on demand

Unit 2

Original EDG Failure Rates (BV2REV3A PRA model)
ZTDGS1 = 9.9991E-04; EDG - failure during first hour

ZTDGS2 = 4.7558E-04; EDG - failure to run after first hour

ZTDGSS = 8.4234E-04; EDG - failure to start on demand

Updated EDG Failure Rates (BV2REV3B PRA model)
ZTDGS1 = 3.3320E-03; EDG - failure during first hour

ZTDGS2 = 7.2520E-04; EDG - failure to run after first hour

ZTDGSS = 2.7771E-03; EDG - failure to start on demand

b. Corrective Action 02-09042-15 involved BVPS-1 EDG unavailability during outages and the impact on credit for the station blackout (SBO) cross-tie to supply BVPS-2. The resolution states that BVPS-1 EDG unavailability during shutdown was subsequently included. Has BVPS-2 EDG unavailability during shutdown been included in the BVPS-1 PRA modeling of the SBO cross-tie from BVPS-2?

Response:

Corrective Action 02-09042-15 resolved a Peer Review F&O by including the Unit 1 EDG shutdown unavailability to the Unit 2 electric power cross-tie model used during a Station Blackout. During the Unit 1 PRA model update, the associated Unit 2 EDG shutdown unavailability was included in the Unit 1 electric power cross-tie model used during Station Blackout events.

For the Unit 1 emergency diesel generators, a shutdown unavailability of 2.1% was obtained based on data from October 1997 through September 2001. This value was then combined with the assumed on-line maintenance unavailability values to determine the total Unit 1 emergency diesel generator unavailability, which was then used in the Unit 2 BV2REV3B electric power cross-tie model.

For the Unit 2 emergency diesel generators, a shutdown unavailability of 1.9% was obtained based on data from March 1999 through February 2002. This value was then combined with the assumed on-line maintenance unavailability values to determine the total Unit 2 emergency diesel generator unavailability, which was then used in the Unit 1 BV1REV3 electric power cross-tie model.

c. For any F&Os unique to BVPS-1, provide a summary of the F&O and its resolution. Please provide confirmation that all Category A and B F&Os on BVPS-1 were resolved prior to the risk assessment of the proposed EDG AOT extension or provide a justification that the resolution is not a significant issue related to the requested EDG AOT change.

Response:

The peer review was conducted in July 2002, by the Westinghouse Owner's Group, with the final documentation of the review issued in December 2002. This peer review primarily focused on the Unit 2 PRA model, but also provided a cursory review of the Unit 1 PRA model and methodology. The majority of F&Os identified in the response to the BVPS Unit 2 Slave Relay Surveillance Test Interval Extension RAI (identified in letter L-03-160 referenced above) were also applicable to Unit 1, and there were some instances where the F&O applied strictly to Unit 2. However, the PRA Peer Review Team did not identify any F&Os that were only unique to Unit 1.

After the peer review, the preliminary Category A and B observations were entered into the BVPS Corrective Action Program, and those that potentially impacted the model were dispositioned, and incorporated into the updated Unit 1 PRA model (BV1REV3). This updated PRA model was then used to quantify the sensitivity cases developed for the Unit 1 14-day EDG AOT extension.

Condition Report 02-09041 was generated to resolve all of the Unit 1 Category A F&Os, and contained three Corrective Actions. All three of these Corrective Actions have been implemented and the Condition Report is closed.

Condition Report 02-09045 was generated to resolve all of the Unit 1 Category B F&Os, and contains thirty-five Corrective Actions. All of the Corrective Actions that were identified as potentially impacting the PRA model have been implemented and are closed. The only remaining Corrective Action that is still open against this Condition Report is Corrective Action 02-09045-23. This corrective action however, is strictly a documentation issue suggesting to include a discussion of the potential impact of floods on systems that are shared between the two units, to the initiating event notebook.

Furthermore, the impact of this F&O on the electric power cross-tie was deemed to be minimal by the PRA Peer Review Team, since multiple River Water/Service Water pumps would remain available to support the EDG cooling requirements, when considering the alternate intake structure pumps.

3. The LAR states that the electric power recovery model "... credits more scenarios with recovery of the fast bus transfer breakers, emergency diesel generators, and the offsite grid." Please describe the model or method used to recover EDGs, including whether this involves repair of emergency diesel generators during the accident sequence. Please explain how the non-repair probabilities were derived. How was the EDG recovery model adjusted to account for the increasing the EDG AOT to 14 days? (RG 1.174, Section 2.2.2; RG 1.177, Section 2.3)

   Response:

   The methodology for recovering the EDGs used in the electric power recovery model is presented in Attachment C. This methodology includes both recovering an EDG due to hardware-related failures during either the startup sequence or the subsequent operation, and diesel generator unavailability due to maintenance at the time of the initiating event.

   It is inherent in the EDG recovery analysis that approximately 20 percent of the single diesel unavailability is assumed to be attributed to preexisting maintenance scenarios. This is captured in the 5th percentile model for the single diesel recovery, which reduces the cumulative frequency of recovery for one diesel by 20 percent. For the 95th percentile, however, a more optimistic view is taken and it is assumed that this fraction of unavailability is recoverable. This will include, for example, restoring the diesel to service after minor maintenance or testing. Finally, because most maintenance events require at least partial reassembly of the diesel generator before it can be started, it is assumed for the 50th percentile that the maintenance contribution to unavailability is also unrecoverable within 2 hours after the initiating event, but is recoverable after 2 hours.

   These EDG recovery curves are assumed to be unaffected by the increased AOT extension time, as the EDG 20 percent non-recoverable value is considered to be bounding.

   In addition, the time-dependent calculations for the integrated electric power failure and recovery model are performed using a Monte Carlo computer simulation program (STADIC). This model computes the following:

   - Conditional probability of onsite power system (diesel generator) failure in a mission time of 24 hours with failure to recover diesel generators or offsite electric power before core damage (designated by the variable QLP in the STADIC code).

   - Conditional probability of onsite power system failure in a 24-hour period without including recovery (designated by the variable QTM in the STADIC code). This part of the analysis uses the cutsets generated by the AC electric power fault trees and accounts for EDG unavailability in the maintenance alignments.

The ratio of QLP/QTM gives the electric power non-recovery factor. Since the conditional probability of the onsite power system failure in a 24-hour period, including EDG unavailability, is factored into both the numerator and denominator, the additional unavailability of EDG due to the 14-day AOT extension will get cancelled out.

Therefore, based upon the above justifications, the electric power recovery model used in support of the 14-day EDG AOT extension will not be impacted.

4. Section 3.3 of the LAR discusses the SBO cross-tie circuitry in the context of station blackout, stating that the BVPS-1 and 2 normal 4KV buses can be cross-tied to allow an EDG from one unit to power SBO loads at both units. Please provide the following information: (RG 1.174, Section 2.2.2; RG 1.177, Section 2.3)

   a. What is the basic human error probability and importance (e.g., Fussell-Vesely) for the operator action to cross-tie the buses? How is dependency among operator actions within a given scenario/sequence addressed when failure to cross-tie is part of the sequence? Describe the operator training content and periodicity for this action. Has the cross-tie capability ever been demonstrated?

   Response:

   The electric power cross-tie model used in the PRA models includes both the plant hardware (e.g., busses and breakers) and operator actions necessary to successfully power both units from a single emergency diesel generator. The operator action human error rates (HER) and Fussell-Vesely (FV) importance associated with the cross-tie include the following:

   ZHEXT1 - Operator Fails to Perform Cross-Tie During SBO

Unit 1 HER = 1.28E-02	FV = 1.61E-03
Unit 2 HER = 3.57E-02	FV = 8.13E-04

   ZHEXT2 - Operator Fails to Perform Cross-Tie During SBO & SLOCA or SGTR

Unit 1 HER = 1.29E-01	FV = 3.67E-06
Unit 2 HER = 4.12E-02*	FV = 2.27E-07

   ZHEXT3 - Operator Fails to Perform Cross-Tie During MLOCA, LLOCA & EXLOCA

Unit 1 HER = 1.0	FV = Not Applicable
Unit 2 HER = 1.0	FV = Not Applicable

   ZHEXT4 - Operator Fails to Manually Align SBO Breakers

Unit 1 HER = 5.30E-02 FV = 2.18E-06

Unit 2 HER = 5.30E-02 FV = 2.52E-07

* Note: The low HER value associated with Unit 2 operator action ZHEXT2 is due to a maximum value of 5.0E-01 being used in calibration tasks during the success likelihood index methodology (SLIM) process, as opposed to a typical value of 1.0. This was due to multiple other actions being assessed in the same HER grouping, which were thought to be bounded by a human error rate of 0.5 at the time that the IPE was performed. BVPS plans on reanalyzing all human action error rates using the EPRI HRA Calculator during the next PRA model update, at each unit.

The cross-tie is only queried if both emergency AC busses have failed and if the necessary hardware is available to support it. The PRA models do not credit the cross-tie if the initiating event is the a loss of an emergency AC bus and the failure of the opposite train normal 4KV bus required to establish the cross-tie. The logic behind this reasoning is that since the initiating event is the loss of an emergency AC bus power, that train is not available to support the cross-tie because the bus could be failed. In addition, since the cross-tie is established through the normal 4KV busses, their failure too could be due to the failure of the bus.

When the cross-tie is attempted but fails, then the operator actions that become important are those in response to a longer term (greater than 1 hour) station blackout. As such, it is important for the operators to establish a long term supply of auxiliary feedwater (AFW) by either aligning dedicated auxiliary feedwater (DAFW) at Unit 1 or makeup to the primary plant demineralized water storage tank (PPDWST) at Unit 2, to cooldown and depressurize the Reactor Coolant System (RCS), and to try to restore offsite power and recover the EDGs. The event trees are constructed so that the dependencies on these operator actions are evaluated with the prior knowledge of what has failed.

For example at Unit 1, with the both trains of emergency AC power unavailable and the cross-tie failed, the PRA event trees evaluate the remaining top events with the knowledge that both trains of emergency AC power are not available (i.e., all top events with only AC powered pumps are guaranteed failed). Since AC power is not available, makeup to the PPDWST is not possible, so operator actions to align the DAFW pump are questioned. However, if AFW was successful, it is known that this operator action only needs to be completed before the PPDWST depletes, and is evaluated as such. Likewise, operator actions to cooldown and depressurize the RCS are evaluated to require local actions since AC power is not available to remotely operate the SG atmospheric steam dump valves. Moreover, if a consequential Power Operated Relief Valve (PORV) LOCA is also present during the SBO, then it is also known that core uncovery will occur quicker than with just a Reactor Coolant Pump (RCP) seal LOCA, so the time to restore offsite power and recover the EDGs is shorter. All of these operator actions are evaluated with the knowledge that the cross-tie has failed and that a station blackout is in progress.

Operator actions to establish the SBO cross-tie and energize SBO loads from the opposite unit are described in separate attachments to the BVPS Emergency Operating Procedures for Loss of All Emergency 4KV AC Power (ECA-0.0). The plant operators that would be responsible for establishing the SBO cross-tie are trained on these attachments during their initial training. Periodic training is conducted on these attachments at a frequency of once every three years. The training content consist of procedure review and a walkdown of the attachments in the plant.

In January, 1993 Emergency Operation Procedures walkthrough validations were performed by the BVPS Unit 1 and Unit 2 Operations personnel to demonstrate that the SBO cross-tie could be established and required SBO loads powered from the opposite unit within one hour, consistent with the BVPS SBO analysis. In addition a SBO cross-tie functional test was performed in May, 1993. This test consisted of energizing a Unit 1 station chiller unit on the 1D non-emergency 4KV bus through the SBO cross-tie from the Unit 2 2A non-emergency 4KV bus. While the test only passed a portion (approximately 28 amps) of the maximum current through the cross-tie that could be expected under SBO condition, the tests also measured voltage drops across the cross-tie cable to verify the design capability for the SBO loads. A similar functional test was again performed in October, 1997 by energizing a Unit 1 station chiller on the 1A non-emergency 4KV bus through the SBO cross-tie from the Unit 2 2D non-emergency 4KV bus.

b. How is the smaller capacity of the BVPS-1 EDGs compared to BVPS-2's (2850kW versus 4535kW) addressed in the PRA modeling?

Response:

The emergency diesel generator capacities used in the PRA electric power cross-tie model are addressed by their respective loss of all AC power (station blackout) emergency operating procedure (ECA-0.0). These procedures first attempt to restore the EDGs and offsite power before establishing the cross-tie. Once the cross-tie is established, these procedures instruct operators to restore AC power to the motor control centers (MCCs) to control AFW throttle valves, SG atmospheric steam dump valves, and re-power battery chargers to restore both 125V DC power and 120V AC vital bus power. These actions allow AFW and steam release to be controlled from the control room for long term decay heat removal and continued cooldown and depressurization of the RCS, which minimize the effects of RCP seal LOCAs.

Since only a limited set of equipment can be powered from the electric power cross-tie, the PRA models do not credit the cross-tie for mitigating excessive, large, or medium LOCAs, as this would require the use of additional ESF equipment to be powered from the EDG. However, if needed, a High Head Safety Injection (HHSI) pump can be powered to mitigate the effects of a small LOCA (e.g., large RCP seal LOCA, or PORV LOCA) or SGTR. If a HHSI pump is to be used, a Unit 1 river water pump must also be powered from the cross-tie, or the diesel driven fire pump must be aligned to the river water header, to support lube oil cooling of the HHSI pump. At Unit 2, the river water header would have to be cross-tied to the service water header to support the Unit 2 HHSI pump. This is due to the smaller Unit 1 EDG capacity, which cannot support the additional load of a Unit 2 service water pump without load shedding. However, the PRA model assumed that the failure probability of the Unit 1 river water pumps was essentially the same as the Unit 2 service water pumps, so this cross-tie between the Unit's cooling water systems was not modeled. That is to say, that the Unit 2 PRA assumes that AC power is available to operate a service water pump if the electric power cross-tie is successful. The diesel driven fire pump is also modeled in the Unit 2 service water PRA model to support the HHSI pump if needed.

It is also assumed in the PRA models that during severe accident conditions at the blackouted unit (e.g., RCP seal LOCA without makeup to the RCS) enough loads could be shed on the remaining EDG to allow for alternate core damage mitigating loads to be started. This would be the case for both the smaller capacity 2850 kW Unit 1 EDG or the 4535 kW Unit 2 EDG. These actions would have to be directed by the Technical Support Center (TSC) and analyzed on a case-by-case basis, since they are not currently accounted for in the station blackout procedure (ECA-0.0). However, the PRA models assume that these actions are successful when implementing the electric power cross-tie, if called upon to mitigate core damage.

Moreover, sensitivity cases were performed by modifying the PRA models to only credit emergency AC power available to the SBO loads identified in ECA-0.0, if the cross-tie is successful. The electric power recovery model was also modified to credit the restoration of offsite power and repair of the EDGs if the cross-tie was successful. The results of these sensitivity cases are as follows:

Case	LAR Submittal	RAI Sensitivity	Delta
Unit 1 - Case 1 CDF	2.34E-05	2.42E-05	8.36E-07
Unit 1 - Case 2 CDF	2.36E-05	2.46E-05	1.00E-06
Unit 1 - Delta CDF	2.08E-07	3.72E-07	1.63E-07
Unit 2 - Case 1 CDF	3.27E-05	3.34E-05	7.08E-07
Unit 2 - Case 2 CDF	3.42E-05	3.51E-05	9.04E-07
Unit 2 - Delta CDF	1.45E-06	1.65E-06	1.96E-07

The Unit 1 Delta CDF = 3.72E-07, or an increase of just 1.63E-07 above the LAR submitted cases. The Unit 2 Delta CDF = 1.65E-06, or an increase of just 1.96E-07 above the submitted cases.

5. Is the BVPS non-safety-related diesel generator credited in the PRA models? If "yes," please provide the basic human error probability and importance (e.g., Fussell-Vesely) of this credit for BVPS-1 and 2. (RG 1.174, Section 2.2.2; RG 1.177, Section 2.3)

Response:

Both the Unit 1 and Unit 2 PRA models credit the non-safety related Emergency Response Facility (ERF) diesel generator. At Unit 1, the ERF diesel generator supports the dedicated auxiliary feedwater pump, which serves as a backup to the turbine-driven AFW pump during SBO events (see Attachment B). At Unit 2, all of the station air compressors and containment air compressors are supported by the ERF diesel generator following a loss of offsite power. The ERF diesel generator automatically starts and loads following a loss of offsite power, without any operator intervention required. As such, there are no human error probabilities associated with the ERF diesel generator. The 4KV and 480V ERF substation power supplies are modeled by Top Event BK, which includes both the feeds from offsite power and the ERF diesel generator along with its support equipment (batteries, fuel oil, cooling, ventilation, and programmable controller panels). The Top Event BK split fraction probabilities and Fussell-Vesely importance for both Unit 1 and Unit 2 are provided below:

<u>Unit 1 PRA model</u>

BK1 - ERF (Black) Diesel Supply, Offsite Power Available
Probability = 1.48E-04   FV = 1.56E-05

BK2 - ERF (Black) Diesel Supply, Loss of Offsite Power
Probability = 8.74E-02   FV = 2.35E-03

<u>Unit 2 PRA model</u>

BK1 - ERF (Black) Diesel Supply, Offsite Power Available
Probability = 2.22E-04   FV = 1.02E-03

BK2 - ERF (Black) Diesel Supply, Loss of Offsite Power
Probability = 7.57E-02   FV = 3.75E-04

6. Please show how the additional 184.4 hours (BVPS-1) and 126.33 hours (BVPS-2) of EDG unavailability were derived, including breakdown by surveillance testing, preventive maintenance (PM) and corrective maintenance (CM). Explain why BVPS-1 and 2 numbers are different.

Response:

Table 1, that follows this response, provides the listing of surveillances and tests conducted on the diesel generators that cause the diesel generator to be unavailable for both Units 1 and 2. The unavailability times were tracked and monitored by the System Engineer. These surveillances and tests are currently performed and will continue to be performed at-power with the extended AOT, with the duration of diesel generator unavailability expected to remain the same as the current AOT. Table 2, that follows this response, provides the surveillance, preventive and corrective maintenance that is normally performed at-power and during outages. These maintenance time durations were based on actual plant experience during at-power and previous outages.

For Unit 1:

The total EDG unavailability with the current EDG AOT for surveillances, tests and repair activities is equal to (37.67 hrs/yr per EDG + 29.92 hrs/yr per EDG) or 67.6 hrs/yr per EDG.

The total EDG unavailability with the extended EDG AOT for surveillances, tests, maintenance and repair activities is equal to (37.67 hrs/yr per EDG + 214.32 hrs/yr per EDG) or 251.99 hrs/yr per EDG.

With the proposed AOT extension, the mean Unit 1 EDG unavailability was estimated to increase from 67.6 hrs/yr per EDG to 251.99 hrs/yr per EDG (or an increase of about 184.4 hrs/yr per EDG).

For Unit 2:

The total EDG unavailability with the current EDG AOT for surveillances, tests and repair activities is equal to (10.5 hrs/yr per EDG + 19.97 hrs/yr per EDG) or 30.47 hrs/yr per EDG.

The total EDG unavailability with the extended EDG AOT for surveillances, tests, maintenance and repair activities is equal to (10.5 hrs/yr per EDG + 146.21 hrs/yr per EDG) or ~156.8 hrs/yr per EDG.

With the proposed AOT extension, the mean Unit 2 EDG unavailability was estimated to increase from 30.47 hrs/yr per EDG to 156.8 hrs/yr per EDG (or an increase of about 126.33 hrs/yr per EDG).

The reasons for different unavailability hours assigned between Unit 1 and Unit 2 are:

During the Unit 1 River Water System surveillance testing the EDG was considered unavailable, while the Unit 2 EDG can be maintained available during the Service Water System testing.

Based on the EDG operating history data the Unit 1 EDG experienced more repairs, and therefore, more corrective maintenance unavailability hours then the Unit 2 EDG.

The Unit 1 and Unit 2 EDGs were manufactured by different companies, and therefore, have different maintenance programs.

Table 1 - Unit 1 Impact of Increased AOTs on Mean Test Downtimes

Test Activity	Current (C) or New (N) Activity	Test Frequency	With Current AOT: Downtime per Test Activity (hr)	With Current AOT: Test Activity Unavail.[1]	Impact of AOT Change on Test Downtime[2]	With Extended AOT[3]: Downtime per Test Activity (hr)	With Extended AOT[3]: Test Activity Unavail.[1]
Monthly Surveillances	C	13/yr (Monthly)	2 hr per DG	26 hr/yr per DG	x1	2 hr per DG	26 hr/yr per DG
Fast Start Ckt Test	C	0.67/yr (18 Month frequency)	4 hr per DG	2.67 hr/yr per DG	x1	4 hr per DG	2.67 hr/yr per DG
RW System Surveillances	C	18/yr (18 events longer than 15 minutes over 12 months)	0.50 hr per event	9 hr/yr per DG	x1	0.50 hr per event	9 hr/yr per DG
Total	---	---	---	37.67 hr/yr per DG	---	---	37.67 hr/yr per DG

Method used to determine test time with extended AOT: No increase in test time with extended AOT

Notes:

1. Test Activity Unavailability = Test Frequency x Downtime per Test Activity
2. Note above the method(s) used for determining the repair and maintenance times with the extended AOT. If a factor increase is used (such as 2X), add the factor to this column.
3. Downtime per Test Activity (with extended AOT) = Impact of AOT Change on Test Downtime x Downtime per Test Activity (with current AOT)

Table 1 - Unit 2 Impact of Increased AOTs on Mean Test Downtimes

Test Activity	Current (C) or New (N) Activity	Test Frequency	With Current AOT: Downtime per Test Activity (hr)	With Current AOT: Test Activity Unavail.[1]	Impact of AOT Change on Test Downtime[2]	With Extended AOT[3]: Downtime per Test Activity (hr)	With Extended AOT[3]: Test Activity Unavail.[1]
Monthly Surveillances	C	13/yr (Monthly)	0.5 hr per DG	6.5 hr/yr per DG	x1	0.5 hr per DG	6.5 hr/yr per DG
Quarterly SI-GO Test	C	4/yr (Quarterly)	1 hr per DG	4 hr/yr per DG	x1	1 hr per DG	4 hr/yr per DG
Total	---	---	---	10.5 hr/yr per DG	---	---	10.5 hr/yr per DG

Method used to determine test time with extended AOT: No increase in test time with extended AOT

Notes:

1. Test Activity Unavailability = Test Frequency x Downtime per Test Activity
2. Note above the method(s) used for determining the repair and maintenance times with the extended AOT. If a factor increase is used (such as 2X), add the factor to this column.
3. Downtime per Test Activity (with extended AOT) = Impact of AOT Change on Test Downtime x Downtime per Test Activity (with current AOT)

Table 2 - Unit 1	**Impact of Increased AOTs on Mean Maintenance Downtimes**						
Maintenance Activity (Note as either Scheduled (S) or Repair (R))	**Current (C) or New (N) Activity**	**Maint. Frequency**	**With Current AOT**		**Impact of AOT Change on Maint. Downtime[2]**	**With Extended AOT[3]**	
			Downtime per Maint. Activity (hr)	**Maint. Activity Unavail.[1]**		**Downtime per Maint. Activity (hr)**	**Maint. Activity Unavail.[1]**
24 Month Surveillance At-Power (S)	N	0.50/yr (24 month frequency)				144 hr per DG	72.0 hr/yr per DG
6 Year Surveillance At-Power (S)	N	0.167/yr (6 year frequency)				168 hr per DG	28.1 hr/yr per DG
12 Year Surveillance At-Power (S)	N	0.083/yr (12 year frequency)				168 hr per DG	13.9 hr/yr per DG
Routine Mid-cycle Maintenance At-Power (S)	C	0.67/yr (18 month frequency)	16 hr per DG	10.72 hr/yr per DG	X1	16 hr per DG	10.72 hr/yr per DG
At-Power Repairs (R), Corrective Maintenance	C	3/yr (6 events in 2 years)	12.8 hr (77 hrs total for the 6 events)	19.2 hr/yr per DG	$X\frac{14}{3}$	59.7 hr	89.6 hr/yr per DG
Total	---	---	---	29.92 hr/yr per DG	---	---	214.32 hr/yr per DG

Method used to determine repair time with extended AOT: Repair time assumed to be increased by the ratio of the 14 day AOT to the current 3 day AOT

Method used to determine scheduled maintenance time with extended AOT: Estimated times from scheduled maintenance performed during refueling outages

Notes:

1. Maintenance Activity Unavailability = Maintenance Frequency x Downtime per Maintenance Activity
2. Note above the method(s) used for determining the repair and maintenance times with the extended AOT. If a factor increase is used (such as 2X), add the factor to this column.
3. Downtime per Maintenance Activity (with extended AOT) = Impact of AOT Change on Maintenance Downtime x Downtime per Maintenance Activity (with current AOT).

Table 2 - Unit 2 Impact of Increased AOTs on Mean Maintenance Downtimes							
Maintenance Activity (Note as either Scheduled (S) or Repair (R))	Current (C) or New (N) Activity	Maint. Frequency	With Current AOT		Impact of AOT Change on Maint. Downtime[2]	With Extended AOT[3]	
			Downtime per Maint. Activity (hr)	Maint. Activity Unavail.[1]		Downtime per Maint. Activity (hr)	Maint. Activity Unavail.[1]
24 Month Surveillance At-Power (S)	N	0.5/yr (24 month frequency)				144 hr per DG	72 hr/yr per DG
13 Year Surveillance At-Power (S)	N	0.077/yr (13 year frequency)				264 hr per DG	20.3 hr/yr per DG
Routine Mid-cycle Maintenance At-Power (S)	C	0.67/yr (18 month frequency)	16 hr per DG	10.72 hr/yr per DG	x1	16 hr per DG	10.72 hr/yr per DG
At-Power Repairs (R)	C	2/yr (4 events in 2 years)	9.25 hr (37 hrs total for the 4 events)	9.25 hr/yr per DG	$\times\frac{14}{3}$	43.17 hr	43.17 hr/yr per DG
Total	---	---	---	19.97 hr/yr per DG	---	---	146.21 hr/yr per DG

Method used to determine repair time with extended AOT: Repair time assumed to be increased by the ratio of the 14 day AOT to the current 3 day AOT

Method used to determine scheduled maintenance time with extended AOT: Estimated times from scheduled maintenance performed during refueling outages

Notes:

1. Maintenance Activity Unavailability = Maintenance Frequency x Downtime per Maintenance Activity
2. Note above the method(s) used for determining the repair and maintenance times with the extended AOT. If a factor increase is used (such as 2X), add the factor to this column.
3. Downtime per Maintenance Activity (with extended AOT) = Impact of AOT Change on Maintenance Downtime x Downtime per Maintenance Activity (with current AOT).

7. The LAR states, in the discussion of Tier 1, that "... past corrective maintenance repair durations were increased by the ratio of the proposed AOT increase when estimating corrective maintenance durations under the proposed AOT." Is this increased duration included in the increase in mean EDG unavailability used to calculate the Case 2 risk? How was the difference in treating common cause failure between CM and PM accounted for in Case 1 and Case 2? (RG 1.174 Section 2.2.1; RG 1.177 Section 2.3.3.1)

   Response:

   The increased duration is included in the increase in mean EDG unavailability used to calculate the Case 2 risk. The response to RAI question # 6 includes Tables 1 and 2, which provide the estimated extended AOT unavailability for surveillances, testing, preventive maintenance, and corrective maintenance unavailability. These unavailability values were calculated based on the estimated yearly average contribution to EDG unavailability for each of the test and maintenance activities. Surveillance and test activities are performed at their required frequencies. Maintenance activities are performed at various maintenance frequencies (from every 18 months to every 13 years).

   When increasing the EDG unavailability due to the 14-day AOT extension, only the maintenance repair duration is increased by the ratio, not the frequency at which repairs are made (i.e., EDG failures were assumed to remain the same). As such, the EDG common cause factors remain unchanged when evaluating Case 1 and Case 2.

   For Unit 1: Case 2's total EDG unavailability with the extended AOT for surveillances, tests, maintenance and repair activities is 251.99 hr/yr per EDG. Therefore, the expected EDG unavailability with the extended AOT is:

$$Percent = (37.67 + 214.32)hr\,/\,yr \times \frac{1yr}{8760hr} \times 100 = 2.88\%$$

   For Unit 2: Case 2's total EDG unavailability with the extended AOT for surveillances, tests, maintenance and repair activities is 156.71 hr/yr per EDG. Therefore, the expected EDG unavailability with the extended AOT is:

$$Percent = (10.5 + 146.21)hr\,/\,yr \times \frac{1yr}{8760hr} \times 100 = 1.79\%$$

   There is no difference in treating common cause failure between corrective maintenance and preventive maintenance accounted for in Case 1 and Case 2. Case 1 models the current EDG unavailability based on the data for current activities. Case 2 models the expected EDG unavailability based on the data for current plus any new activities. Both cases modeled the same maintenance alignments and the same common cause failures.

8. Please provide a discussion on the effects of the proposed AOT extension on dominant accident sequences (sequences that contribute more that 5% to risk, for example) to show that the proposed change does not create risk outliers or exacerbate existing risk outliers. Please provide core damage contributions by initiating event (including seismic and fire) and by sequence type for Cases 1 and 2. (RG 1.174, Section 3.3.1)

   Response:

   Based on a comparison of the dominant CDF sequences for both Unit 1 and Unit 2, no new risk outliers were identified, and existing outliers were not exacerbated. Tables 3 and 4 provide the top five sequences contributing to CDF for both Unit's Case 1 and Case 2, respectively. As can be seen in the tables, only the first sequence in both cases at each Unit would be considered dominant, according to the Regulation Guide 1.174 definition (i.e., sequences that contribute more than 5% to the risk).

   For Case 1, the Unit 1 initiating event CDF contributions are presented in Table 5, while Table 6 presents the Unit 1 sequence type contributions. For Case 2, the Unit 1 initiating event CDF contributions are presented in Table 7, while Table 8 presents the Unit 1 sequence type contributions. At Unit 2, the Case 1 initiating event CDF contributions are presented in Table 9, while Table 10 presents the Case 1 sequence type contributions. For Case 2, the Unit 2 initiating event CDF contributions are presented in Table 11, while Table 12 presents the Unit 2 sequence type contributions.

Table 3
Case 1 CDF Sequences

Rank	Initiator	Frequency	Failed and Multi-State Split Fractions	% of CDF
Unit 1				
1	CS1L1C	1.7945E-06	ZXF*BVA*CCF*TBF*PL1*AFF*MFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	7.7%
2	SEIS3	5.0791E-07	ZC3*ZD3*ZB3*OGF*NAF*NDF*AOF*BPF*XTF*M5F*M1F*M3F*M6F*M2F*M4F*DOF*DPF*D3F*D4F*IRF*IBF*IWF*IYF*SAF*SBF*OSF*BKF*WAF*WBF*CTF*CCF*TBF*TTF*MSF*PL1*ASF*AFF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	2.2%
3	SEIS2	4.4960E-07	ZC2*ZD2*ZB2*OGF*NAF*NDF*AOF*BPF*XTF*M5F*M1F*M3F*M6F*M2F*M4F*DOF*DPF*D3F*D4F*IRF*IBF*IWF*IYF*SAF*SBF*OSF*BKF*WAF*WBF*CTF*CCF*TBF*TTF*MSF*PL1*ASF*AFF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	1.9%
4	SEIS3	4.0336E-07	ZC3*ZB3*ZG3*OGF*NAF*NDF*BKF*WAF*WBF*CTF*CCF*TBF*PL1*MAF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*ODF*NRF*NMF*QAF*QBF*SMF*REF*SSF*CG1	1.7%
5	SEIS3	3.9929E-07	ZP3*ZC3*ZB3*OGF*NAF*NDF*BKF*WAF*WBF*CTF*CCF*TBF*PL1*MAF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*ODF*NRF*NMF*QAF*QBF*SMF*REF*SSF*CG1	1.7%
Unit 2				
Rank	**Initiator**	**Frequency**	**Failed and Multi-State Split Fractions**	**% of CDF**
1	AOX	1.9298E-06	ZXF*AOF*BP1*XTD*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*REF*SSF*CG1	5.9%
2	BPX	9.4435E-07	ZXF*AO1*BPF*XTG*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*REF*SSF*CG1	2.9%
3	EXFW	6.2338E-07	ZXF*PL1*AF1*MFF*OB1*CDF*ODF*RRF*NRF*NMF*REF*SSF*CG1	1.9%
4	CB3L1P	6.0024E-07	ZXF*CSF*IAF*ICF*TBF*MSF*PL1*AFF*OFF*OB4*CDF*ODF*RRF*NRF*NMF*REF*SSF*CG1	1.8%
5	BPX	5.4149E-07	ZXF*NA1*AO2*BPF*XTF*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*RESA*SSF*CG1	1.7%

Table 4 Case 2 CDF Sequences				
Unit 1				
Rank	**Initiator**	**Frequency**	**Failed and Multi-State Split Fractions**	**% of CDF**
1	CS1L1C	1.7945E-06	ZXF*BVA*CCF*TBF*PL1*AFF*MFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	7.6%
2	SEIS3	5.0791E-07	ZC3*ZD3*ZB3*OGF*NAF*NDF*AOF*BPF*XTF*M5F*M1F*M3F*M6F*M2F*M4F*DOF*DPF*D3F*D4F*IRF*IBF*IWF*IYF*SAF*SBF*OSF*BKF*WAF*WBF*CTF*CCF*TBF*TTF*MSF*PL1*ASF*AFF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	2.2%
3	SEIS2	4.4960E-07	ZC2*ZD2*ZB2*OGF*NAF*NDF*AOF*BPF*XTF*M5F*M1F*M3F*M6F*M2F*M4F*DOF*DPF*D3F*D4F*IRF*IBF*IWF*IYF*SAF*SBF*OSF*BKF*WAF*WBF*CTF*CCF*TBF*TTF*MSF*PL1*ASF*AFF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*CDF*NRF*NMF*QAF*QBF*SMF*CIF*REF*SSF*CG1	1.9%
4	IAX	3.9583E-07	ZXF*IAF*ICF*TBF*PL1*VL1*HCF*SEF*RL2*CDB*NRF*NMF*REF*SSF*CG1	1.7%
5	SEIS3	3.8607E-07	ZC3*ZB3*ZG3*OGF*NAF*NDF*BKF*WAF*WBF*CTF*CCF*TBF*PL1*MAF*MFF*DFF*OFF*OBF*HHF*SEF*RL1*LAF*LBF*ODF*NRF*NMF*QAF*QBF*SMF*REF*SSF*CG1	1.6%
Unit 2				
Rank	**Initiator**	**Frequency**	**Failed and Multi-State Split Fractions**	**% of CDF**
1	AOX	1.9303E-06	ZXF*AOF*BP1*XTD*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*REF*SSF*CG1	5.6%
2	BPX	9.4475E-07	ZXF*AO1*BPF*XTG*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*REF*SSF*CG1	2.8%
3	BPX	7.4397E-07	ZXF*NA1*AO2*BPF*XTF*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*RE5A*SSF*CG1	2.2%
4	AOX	6.3891E-07	ZXF*ND2*AOF*BP8*XTF*M1F*M2F*M3F*M4F*WAF*WBF*CSF*CCF*TBF*PL1*HHF*HCF*SEF*RL1*LHF*LCF*RRF*NRF*NMF*QSF*SMF*RE5A*SSF*CG1	1.9%
5	EXFW	6.2338E-07	ZXF*PL1*AF1*MFF*OB1*CDF*ODF*RRF*NRF*NMF*REF*SSF*CG1	1.8%

Unit 1 Dominant Sequence Comparison

Based on the comparison of these sequences at Unit 1, it can be seen that there are no differences in the top three sequences. Sequence 1 remains essentially unaffected by the increased EDG AOT, since the PRA model assumes that all AC power is failed and non-recoverable due to the loss of emergency switchgear ventilation (split fraction BVA). For sequences 2 and 3, the emergency AC busses are set to guaranteed failures (split fractions AOF & BPF) and are non-recoverable due the seismic initiating events (SEIS3 and SEIS2).

For Table 3 Case 1, sequences 4 and 5 are also initiated by seismic events, with the seismically induced failure of the offsite grid (ZC3), ERF diesel generator substation (ZB3), and river water system due to either the collapse of the intake structure (ZG3) or primary auxiliary building (ZP3). For these sequences, the EDGs successfully start and load to supply the emergency busses following the loss of offsite power. However, with all river water cooling failed the EDGs soon fail along with the emergency AC busses. These sequences show up as sequence 5 in Table 4, and what would be sixth ranked sequence for Case 2, with a frequency of 3.8217E-07. As can been seen Table 4 sequence 5, there was a slight reduction in frequency when compared to Table 3 sequence 4. This difference in frequency can be attributed to the success terms of the emergency AC power split fractions. Since there were no failures of the EDGs observed in these sequences, the 14-day EDG AOT extension sequence frequency would be lower since the success term (one minus the failure term) would have a smaller value than for the base case, due to the higher failure probability associated with increased EDG unavailability. For example, the AO2 split fraction value associated with the emergency AC orange train, given that the normal 4KV bus 1A failed (e.g., loss of offsite power) is 1.1830E-01 for Case 1 and 1.3703E-01 for Case 2, with the increase in frequency due to the increased EDG unavailability. The associated success term values for sequences in which AO2 is successful would be 1.0 minus 1.1830E-01 or 0.88170 for Case 1, and 1.0 minus 1.3703E-01 or 0.86297 for Case 2. Therefore, Case 2 sequences would be lower in frequency than the associated Case 1 sequences, whenever split fraction AO2 is successful. This same reasoning would also be true for Table 3 sequence 5, which was reduced in frequency from 3.9929E-07 to 3.8217E-07.

The fourth ranked sequence in Table 4 is essentially the same as what would be the sixth ranked sequence for Case 1. Since offsite power is available in this sequence, the impact of the increased EDG unavailability associated with the 14-day AOT is minor and the reduction in the success terms is insignificant.

<u>Unit 1 - Case 2 Sequence Progression Description</u>

Sequence 1: This sequence is initiated by one of the 3 clustered emergency switchgear ventilation fans (VS-F-16A, 16B, 55A) igniting with a fire radius greater than 6 feet that destroys one of the other nearby fans, with a subsequent failure of the operators to align portable ventilation. The loss of all emergency switchgear ventilation then leads to a total loss of all Emergency AC and DC Power, and also fails the vital buses. The operators go to ECA-0.0, but are unsuccessful in establishing a cross-tie to the Unit 2 Emergency Diesel Generators, primarily due to non-recoverable failures of the Emergency AC Power equipment from overheating. This results in an extended loss of all Emergency AC and DC Power at Unit 1, and a 21-gpm/RCP Seal LOCA develops. Additionally, no credit for electric power recovery to the Emergency AC buses is taken, since it is assumed that they cannot be repaired in the 24-hour mission time. Without any emergency AC power, RCS inventory makeup is not available. Auxiliary Feedwater is also assumed to be unavailable due to the loss of AC power to the motor driven AFW pumps and loss of instrumentation (vital bus failures) to support the turbine driven AFW pump. Without any instrumentation, the operators are also unsuccessful in aligning an MFW or Dedicated AFW pump, or establishing bleed and feed cooling. This leads to the Steam Generators drying out and increasing the RCS pressure above the RCS safety valve lift setpoint. As the safety valves open, RCS inventory is lost and pressure decreases, until the RCS pressure is below the safety valve reseat pressure. Once the safety valves close, the loss of RCS inventory is terminated; however, the RCS pressure increases again until the safety valves lift. This process keeps on cycling, and eventually the core uncovers at about 1.9 hours following the loss of all power, with core damage occurring shortly after, at approximately 2.1 hours.

Sequence 2: This sequence is initiated by a seismic event with the earthquake ground acceleration in the 0.35-g to 0.50-g range. Since the plant was seismically designed to ground accelerations below 0.125-g, massive structural damage occurs. This leads to the seismic failure of the Emergency DC Battery block walls and all components located within. Additionally, seismic failures of the Offsite Grid and the ERF Diesel Generator occur. These failures lead to a Station Blackout (loss of all Normal and Emergency AC Power) along with a loss of all DC power to the station, since the Emergency Diesel Generators would fail to start following a loss of Offsite Power, due to the failure of the Emergency DC Batteries. No credit for the cross-tie to the Unit 2 Emergency Diesel Generators or electric power recovery to the Emergency AC buses is taken since DC power is not available to restart any equipment. The remaining sequence of events is the same as Sequence 1, following the extended loss of all Emergency AC and DC Power.

Sequence 3: This sequence is also initiated by a seismic event, except this time the earthquake ground acceleration is in the 0.25-g to 0.35-g range. Since the plant was seismically designed to ground accelerations below 0.125-g, massive structural damage occurs that results in the same components failures as in Sequence 2. The remaining sequence of events is therefore the same as Sequence 2.

Sequence 4: This sequence is initiated by a loss of Station Instrument Air, which results in the failure of RCP thermal barrier cooling due to the isolation valves failing closed. The loss of air also results in letdown isolation, which cause a low Volume Control Tank (VCT) level and signal to swapover to the Refueling Water Storage Tank (RWST). However, swapover to the RWST does not occur due to either the RWST check valve (SI-27) not opening or the RWST/VCT MOVs fail to open/close. This results in the cavatation and failure of HHSI pumps, which leads to a loss of RCP seal injection. Without any RCP thermal barrier cooling or RCP seal injection a 21-gpm/RCP Seal LOCA develops. After about 30 minutes following the RCP Seal LOCA initiation, the RCP Second Stage Seals fail and the 21-gpm/RCP Seal LOCA develops into a 57-gpm/RCP Seal LOCA. Auxiliary Feedwater is available but the operators are unsuccessful in the cooldown and depressurization of the RCS. Without any HHSI, RCS conditions degrade to some point where entry into EOP FR-C.1 occurs. However, without the ability to depressurize the RCS for LHSI injection or recovery of the HHSI, there is no makeup to the RCS and the core eventually uncovers at about 25 hours with subsequent core damage at 28 hours.

Sequence 5: This sequence is also initiated by a seismic event with the earthquake ground acceleration in the 0.35-g to 0.50-g range. Since the plant was seismically designed to ground accelerations below 0.125-g, massive structural damage occurs that results in the seismic failure of the River Water and Auxiliary River Water Intake Structures, as well as the Offsite and ERF AC power supplies. Both of the Emergency Diesel Generators successfully start and supply power to the Emergency AC buses following the loss of Offsite Power. However, due to the structural damage of the Intake Structures, the River Water pumps catastrophically fail, leading to the loss of all River Water/Auxiliary River Water. This consequently leads to the failure of the Emergency Diesel Generators due to loss of cooling, and a Station Blackout (loss of all Normal and Emergency AC Power) occurs. These failures lead to the loss of all RCP seal cooling and a 21-gpm/RCP Seal LOCA develops. Dedicated AFW is unavailable due to the seismic failure of the ERF power, but Auxiliary Feedwater is available via the turbine driven AFW pump and the operators successfully cooldown and depressurize the RCS, which reduces the RCP seal leakage and conditions stabilize. However due to the SBO, after about 3.8 hours the batteries supplying power for the Steam Generator level indication depletes, and the operators are forced to leave the AFW flow control valves in their last known position. Due to the core decay heat reduction over time, the fixed AFW flow eventually overfills the Steam Generators after about 11 hours, which leads to water ingestion and failure of the turbine driven AFW pump. Without any AFW, the Steam Generators eventually dryout and the RCS quickly repressurizes; thereby, increasing the RCS break flow through the RCP seals and eventually lifting RCS safety valves. Once the safety valves open, the increase in RCS leakage rapidly leads to core uncovery at about 19 hours, with core damage occurring shortly after, at approximately 20 hours.

<u>Unit 2 Dominant Sequence Comparison</u>

Based on the comparison of these top five sequences at Unit 2, it too can be seen that there are no differences in the top two sequences, other than the frequency at which they occur. For these sequences, a loss of one train of emergency AC power is the initiating event, with the probabilistic failure of the opposite train of emergency AC. These differences in the sequence frequencies can be attributed to the slight increase in the emergency AC power probabilistic split fraction (BP1 and AO1) values. For these split fractions, since offsite power remains available in the sequences, the impact of the increased EDG unavailability associated with the 14-day AOT is only minor.

Table 3 Case 1, sequence 3 and Table 4 Case 2, sequence 5 are also the same sequence with the same frequency. This sequence is initiated by an excessive main feedwater event. Since offsite power and both emergency AC busses are available in this sequence, the impact of the increased EDG unavailability associated with the 14-day AOT is minor and the reduction in the success terms is insignificant.

The fourth ranked sequence in Table 3 Case 1 is essentially the same as what would be the sixth ranked sequence for Case 2, with a frequency of 6.0023E-07. This sequence is initiated by a fire in the Control Room Benchboard Sections C1 and C2, and spreads to Section C3. Once again, since offsite power is available in this sequence, the impact of the increased EDG unavailability associated with the 14-day AOT is minor and the reduction in the success terms is insignificant.

Sequences 3 and 4 in Table 4 Case 2 are essentially the same as sequence 5 in Table 3 Case 1 and what would be the sixth ranked sequence for Case 1, with a frequency of 4.6534E-07. For these sequences, a loss of one train of emergency AC power is the initiating event, with the probabilistic failure of the opposite train of normal 4KV and emergency AC power. Since the normal 4KV bus fails, there is a need for the associated EDG to start, load, and run for the 24-hour mission time modeled. Failure of emergency AC power split fractions (AO2 and BP8) in these sequences implies that there is a high likelihood that EDGs failures were observed. Therefore, the 14-day EDG AOT extension sequence frequencies in Table 4 Case 2 are higher than the associated Case 1 frequencies, due to the higher failure probability associated with increased EDG unavailability. However, the total increase in risk associated with these 14-day EDG AOT extension sequences is approximately 3.8E-07, and is not considered to significantly exacerbate the sequence risk.

Unit 2 - Case 2 Sequence Progression Description

Sequence 1: This sequence is initiated by a loss of Emergency AC Orange Power (which is assumed to be non-recoverable), with a subsequent failure of Emergency AC Purple Power, mostly due to 480VUS-2-9 bus unavailability or equipment failures of the 4KVS-2DF bus. The operators go to ECA-0.0, but are unsuccessful in establishing a cross-tie to the Unit 1 Emergency Diesel Generators, primarily due to non-recoverable failures of the Emergency AC Purple Train equipment. This results in an extended loss of all Emergency AC Power at Unit 2, and a 21-gpm/RCP seal LOCA develops. Additionally, no credit for electric power recovery to the 2DF Emergency AC bus is taken, since the bus failed even though offsite power and the Emergency Diesel Generator were available. Without any emergency AC power, RCS inventory makeup is not available. Auxiliary Feedwater is available via the turbine driven AFW pump and the operators successfully cooldown and depressurize the RCS, which reduces the RCP seal leakage and conditions stabilize. However, after about 8 hours the batteries supplying power for the Steam Generator level indication depletes, and the operators are forced to leave the AFW flow control valves in their last known position. Due to the core decay heat reduction over time, the fixed AFW flow eventually overfills the Steam Generators after about 22 hours, which leads to water ingestion and failure of the turbine driven AFW pump. Without any AFW, the Steam Generators eventually dryout and the RCS quickly repressurizes; thereby, increasing the RCS break flow through the RCP seals and eventually lifting RCS safety valves. Once the safety valves open, the increase in RCS leakage rapidly leads to core uncovery at about 37 hours, with core damage occurring shortly after, at approximately 38 hours.

Sequence 2: This sequence is similar to the first sequence; however this time the initiator is a loss of Emergency AC Purple Power, with a subsequent failure of Emergency AC Orange Power. In this sequence the operators are also unsuccessful in establishing a cross-tie to the Unit 1 Emergency Diesel Generators, but this time it is primarily due to non-recoverable failures of the Emergency AC Orange Train equipment. Additionally, no credit for electric power recovery to the 2AE Emergency AC bus is taken, since the bus failed even though offsite power and the Emergency Diesel Generator were available. This also results in a 21-gpm/RCP seal LOCA due to the extended loss of all Emergency AC Power. The remaining sequence of events is the same as Sequence 1, following the RCP seal LOCA initiation. This sequence has about half the frequency of occurring compared to the first, due to no historical maintenance unavailability of the 480VUS-2-8 bus during the update period; whereas, the 480VUS-2-9 bus had 2.75 hours of unavailability.

Sequence 3: This sequence is also initiated by a loss of Emergency AC Purple Power; however, this time a subsequent failure of the Normal 4KVS-2A bus occurs during the fast bus transfer to offsite power. This leads to a demand on the No.1 Emergency Diesel Generator (2EGS-EG2-1), which is unsuccessful, thereby causing a failure of Emergency AC Orange Power. The operators go to ECA-0.0 and try to restore Normal AC Power to the 2A bus, but are unsuccessful in their attempts to repair/replace the fast bus transfer breakers. Without the Normal 4KVS-2A bus to supply power to the Emergency AC Orange bus, and a non-recoverable failure of the Emergency AC Purple bus, there is no way to establish a cross-tie to the Unit 1 Emergency Diesel Generators, so no credit is given. This results in an extended loss of all Emergency AC Power with a loss of the Normal 4KVS-2A bus at Unit 2, and a 21-gpm/RCP seal LOCA develops. The remaining sequence of events is the same as Sequence 1, following the RCP seal LOCA initiation.

Sequence 4: This sequence is initiated by a loss of Emergency AC Orange Power, with a subsequent failure of the Normal 4KVS-2D bus that occurs during the fast bus transfer to offsite power. This leads to a demand on the No.2 Emergency Diesel Generator (2EGS-EG2-2), which is unsuccessful, thereby causing a failure of Emergency AC Purple Power. The operators go to ECA-0.0 and try to restore Normal AC Power to the 2D bus, but are unsuccessful in their attempts to repair/replace the fast bus transfer breakers. Without the Normal 4KVS-2D bus to supply power to the Emergency AC Purple bus, and a non-recoverable failure of the Emergency AC Purple bus, there is no way to establish a cross-tie to the Unit 1 Emergency Diesel Generators, so no credit is given. This results in an extended loss of all Emergency AC Power with a loss of the Normal 4KVS-2D bus at Unit 2, and a 21-gpm/RCP seal LOCA develops. The remaining sequence of events is the same as Sequence 1, following the RCP seal LOCA initiation.

Sequence 5: This sequence is initiated by an excessive feedwater event that results in Main Feedwater isolation. Eventually the loss of MFW leads to a steam generator low-low level and an Auxiliary Feedwater initiation signal, which subsequently fails. The conditions warrant entry into EOP FR-H.1, but the operators fail to implement RCS bleed and feed cooling. This leads to the Steam Generators drying out and increasing the RCS pressure above the PORV lift setpoint. As the PORVs open, RCS inventory is lost and pressure decreases, until the RCS pressure is below the PORV reseat pressure. Once the PORVs close, the loss of RCS inventory is terminated; however, the RCS pressure increases again until the PORVs lift. This process keeps on cycling, and eventually the core uncovers. At this point, the operators would normally enter into EOP FR-C.1 to initiate HHSI and depressurize the RCS to restore core cooling (essentially bleed and feed cooling). However, even if the operators were successful in manually actuating HHSI at this time, the flow rate would not be adequate to keep up with the inventory lost out the PORVs at these RCS pressures. Therefore, no credit is given for these actions since they were unsuccessful in EOP FR-H.1.

Table 5

Unit 1 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
AMSIVA	1.45E-02	2.74E-11	0.00%	CLOSURE OF ALL MSIV'S - ATWS
AOXA	2.04E-02	1.85E-09	0.01%	LOSS OF EMERGENCY 4160V AC ORANGE - ATWS
BPXA	2.04E-02	2.04E-09	0.01%	LOSS OF EMERGENCY 4160V AC PURPLE - ATWS
CCXA	3.14E-03	4.00E-12	0.00%	LOSS OF REACTOR COMPONENT COOLING WATER - ATWS
DOXA	3.38E-02	1.30E-08	0.06%	LOSS OF EMERGENCY 125V DC ORANGE - ATWS
DPXA	3.38E-02	5.95E-09	0.03%	LOSS OF EMERGENCY 125V DC PURPLE-ATWS
EXFWA	1.90E-01	1.44E-08	0.06%	EXCESSIVE FEEDWATER FLOW - ATWS
IAXA	7.89E-02	6.07E-09	0.03%	LOSS OF STATION INSTRUMENT AIR - ATWS
IBXA	6.00E-03	3.02E-09	0.01%	LOSS OF VITAL BUS III (BLUE) - ATWS
ICXA	1.25E-02	2.37E-11	0.00%	CNMT INST AIR INITIATING EVENT - ATWS
IMSIVA	1.89E-01	1.41E-08	0.06%	CLOSURE OF ONE MSIV - ATWS
IRXA	6.00E-03	9.79E-11	0.00%	LOSS OF VITAL BUS I (RED) - ATWS
ISIA	9.56E-02	7.09E-09	0.03%	INADVERTANT SAFETY INJECTION INITIATION - ATWS
IWXA	6.00E-03	1.03E-10	0.00%	LOSS OF VITAL BUS II (WHITE) - ATWS
IYXA	6.00E-03	2.11E-09	0.01%	LOSS OF VITAL BUS IV (YELLOW) - ATWS
LB1AA	3.85E-03	5.41E-11	0.00%	LOSS OF NORMAL 4KV BUS 1A - ATWS
LB1DA	3.52E-03	4.61E-11	0.00%	LOSS OF NORMAL 4KV BUS 1D - ATWS
LCVA	1.34E-01	3.01E-10	0.00%	LOSS OF CONDENSER VACUUM - ATWS
LOSPA	3.16E-02	8.98E-09	0.04%	LOSS OF OFFSITE POWER - ATWS
LOPFA	9.09E-02	1.99E-10	0.00%	LOSS OF PRIMARY FLOW - ATWS
MFWLBA	2.62E-03	1.84E-10	0.00%	MAIN FEEDWATER LINE BREAK - ATWS
MSVA	9.76E-04	1.12E-10	0.00%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING - ATWS
PLMFWA	5.88E-01	4.47E-08	0.19%	PARTIAL LOSS OF MAIN FEEDWATER - ATWS
SGTRAA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR A TUBE RUPTURE - ATWS
SGTRBA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR B TUBE RUPTURE - ATWS
SGTRCA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR C TUBE RUPTURE - ATWS
SLBIA	8.49E-04	1.04E-10	0.00%	STEAMLINE BREAK INSIDE CONTAINMENT - ATWS
SLBCA	1.54E-03	1.81E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE - ATWS
SLBDA	4.58E-03	5.54E-10	0.00%	STEAM LINE BREAK OUTSIDE CONTAINMENT - ATWS
TLMFWA	4.85E-02	3.63E-09	0.02%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIPA	7.17E-01	1.74E-09	0.01%	TURBINE TRIP - ATWS
WCXA	3.80E-06	1.25E-11	0.00%	LOSS OF RIVER WATER HEADERS A & B - ATWS
		1.48E-07	**0.63%**	**ATWS TOTAL**
AF1L1C	1.31E-06	2.66E-11	0.00%	DETAILED FIRE SCENARIO AF1-L-1C
CR1L1A	3.10E-05	1.51E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1A
CR1L1B	2.95E-05	1.43E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1B

Table 5

Unit 1 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
CR1L1C	4.57E-05	2.22E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1C
CR1L1D	4.27E-05	2.08E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1D
CR1L1F	2.95E-05	1.43E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1F
CR1L1G	9.14E-05	5.81E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1G
CR1L1O	5.71E-06	8.18E-08	0.35%	DETAILED FIRE SCENARIO CR1-L-1O
CR1L1P	1.47E-05	2.11E-07	0.90%	DETAILED FIRE SCENARIO CR1-L-1P
CR1L1Q	3.54E-06	5.07E-08	0.22%	DETAILED FIRE SCENARIO CR1-L-1Q
CR1L1S	1.62E-06	5.02E-08	0.21%	DETAILED FIRE SCENARIO CR1-L-1S
CR3L1E	8.78E-07	6.17E-08	0.26%	DETAILED FIRE SCENARIO CR3-L-1E
CR3L1F	8.61E-06	1.97E-12	0.00%	DETAILED FIRE SCENARIO CR3-L-1F
CR3L1G	8.10E-07	5.69E-08	0.24%	DETAILED FIRE SCENARIO CR3-L-1G
CR3P1A	2.47E-07	1.73E-08	0.07%	DETAILED FIRE SCENARIO CR3-P-1A
CR4L1A	2.22E-04	1.58E-10	0.00%	DETAILED FIRE SCENARIO CR4-L-1A
CR4L1C	1.90E-07	1.90E-07	0.81%	DETAILED FIRE SCENARIO CR4-L-1C
CR4L1D	1.13E-07	1.13E-07	0.48%	DETAILED FIRE SCENARIO CR4-L-1D
CR4L1E	5.65E-07	3.96E-08	0.17%	DETAILED FIRE SCENARIO CR4-L-1E
CR4L1O	2.74E-07	1.92E-08	0.08%	DETAILED FIRE SCENARIO CR4-L-1O
CR4L1P	8.01E-08	8.00E-08	0.34%	DETAILED FIRE SCENARIO CR4-L-1P
CRL1AC	2.89E-05	1.42E-09	0.01%	DETAILED FIRE SCENARIO CR1-L-1AC
CRL1AP	2.89E-05	1.20E-09	0.01%	DETAILED FIRE SCENARIO CR1-L-1AP
CRL1EB	4.93E-05	1.10E-09	0.00%	DETAILED FIRE SCENARIO CR1-L-1EB
CRP1AE	5.34E-05	2.61E-08	0.11%	DETAILED FIRE SCENARIO CR1-P-1AE
CS1L1A	3.95E-05	1.92E-11	0.00%	DETAILED FIRE SCENARIO CS1-L-1A
CS1L1B	5.39E-06	4.26E-07	1.81%	DETAILED FIRE SCENARIO CS1-L-1B
CS1L1C	3.23E-05	2.55E-06	10.85%	DETAILED FIRE SCENARIO CS1-L-1C
CS1L1D	1.07E-04	7.02E-11	0.00%	DETAILED FIRE SCENARIO CS1-L-1D
CS1L1E	1.80E-06	1.27E-07	0.54%	DETAILED FIRE SCENARIO CS1-L-1E
CS1L1F	2.05E-07	1.43E-08	0.06%	DETAILED FIRE SCENARIO CS1-L-1F
CV1L1A	1.20E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1A
CV1L1B	8.12E-06	1.62E-10	0.00%	DETAILED FIRE SCENARIO CV1-L-1B
CV1L1D	7.46E-06	1.71E-12	0.00%	DETAILED FIRE SCENARIO CV1-L-1D
CV1L1G	1.14E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1G
CV1L1H	7.26E-07	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1H
CV2L1A	7.02E-06	1.60E-12	0.00%	DETAILED FIRE SCENARIO CV2-L-1A
CV2L1E	1.20E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV2-L-1E
CV2L1F	1.47E-05	5.97E-12	0.00%	DETAILED FIRE SCENARIO CV2-L-1F
CV3L1A	3.11E-06	2.19E-07	0.93%	DETAILED FIRE SCENARIO CV3-L-1A
CV3L1B	1.16E-06	8.15E-08	0.35%	DETAILED FIRE SCENARIO CV3-L-1B
DG1L1A	9.08E-03	4.52E-08	0.19%	DETAILED FIRE SCENARIO DG1-L-1A
DG2L1A	9.00E-03	4.44E-08	0.19%	DETAILED FIRE SCENARIO DG2-L-1A

Table 5

Unit 1 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
ES1AE1	1.40E-04	1.69E-08	0.07%	DETAILED FIRE SCENARIO ES1AE-L-1
ES1DF1	1.61E-04	1.21E-08	0.05%	DETAILED FIRE SCENARIO ES1DF-L-1
NS1L1B	1.83E-07	1.28E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1B
NS1L1G	4.57E-08	3.17E-09	0.01%	DETAILED FIRE SCENARIO NS1-L-1G
NS1L1I	4.57E-08	3.17E-09	0.01%	DETAILED FIRE SCENARIO NS1-L-1I
NS1L1J	1.84E-07	1.29E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1J
NS1L1K	2.75E-07	1.93E-08	0.08%	DETAILED FIRE SCENARIO NS1-L-1K
NS1L1L	2.75E-07	1.93E-08	0.08%	DETAILED FIRE SCENARIO NS1-L-1L
NS1L1M	1.84E-07	1.29E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1M
NS1L1Q	1.80E-07	1.26E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1Q
PA1ELC	6.43E-07	7.12E-09	0.03%	DETAILED FIRE SCENARIO PA1E-L-1C
PA1ELE	6.43E-07	7.12E-09	0.03%	DETAILED FIRE SCENARIO PA1E-L-1E
PA1ELF	4.29E-07	4.74E-09	0.02%	DETAILED FIRE SCENARIO PA1E-L-1F
PA1ELG	1.07E-07	1.17E-09	0.00%	DETAILED FIRE SCENARIO PA1E-L-1G
PA1ELH	2.14E-07	2.36E-09	0.01%	DETAILED FIRE SCENARIO PA1E-L-1H
PA1ELI	2.14E-07	2.36E-09	0.01%	DETAILED FIRE SCENARIO PA1E-L-1I
PA1ELM	6.09E-08	6.63E-10	0.00%	DETAILED FIRE SCENARIO PA1E-L-1M
PA1GDB	2.54E-05	1.14E-11	0.00%	DETAILED FIRE SCENARIO PA1GD-L-1B
PA1GDH	9.03E-06	1.01E-09	0.00%	DETAILED FIRE SCENARIO PA1GD-L-1H
PNAP1A	1.14E-04	9.09E-11	0.00%	DETAILED FIRE SCENARIO PNA-P-1A
PT1ALA	1.44E-04	1.09E-10	0.00%	DETAILED FIRE SCENARIO PT1A-L-A
PT1APA	2.22E-05	9.07E-12	0.00%	DETAILED FIRE SCENARIO PT1A-P-1A
RC1L1	1.46E-02	2.31E-08	0.10%	DETAILED FIRE SCENARIO RC1-L-1
TB1ALA	2.39E-04	3.89E-09	0.02%	DETAILED FIRE SCENARIO TB1A-L-1A
TG1P1A	1.47E-04	2.38E-09	0.01%	DETAILED FIRE SCENARIO TG1-P-1A
		4.69E-06	**19.95%**	**INTERNAL FIRES TOTAL**
CRFL	3.29E-06	1.95E-09	0.01%	FLOOD IN CONTROL BLDG HVAC ROOM
CVFL	1.50E-04	1.50E-11	0.00%	WEST CABLE VAULT FLOOD
ISFLA	9.01E-04	3.64E-09	0.02%	INTAKE STRUCTURE FLOOD IN CUBICLE A
ISFLB	6.76E-04	2.74E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE B
ISFLC	6.76E-04	2.08E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE C
ISFLD	1.13E-03	1.56E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE C
PABF1A	3.85E-04	1.39E-08	0.06%	PAB FLOOD AT EL 735 RW TRN A - ISOLATED
PABF1B	3.85E-04	8.48E-09	0.04%	PAB FLOOD AT EL 735 RW TRN B - ISOLATED
PABF2A	2.53E-05	2.83E-07	1.20%	PAB FLOOD AT EL 735 TRN A - NOT ISOLATED
PABF2B	2.53E-05	2.83E-07	1.20%	PAB FLOOD AT EL 735 TRN B - NOT ISOLATED
PABF3A	3.90E-04	1.20E-08	0.05%	PAB FLOOD AT EL 722 TRN A - EARLY ISOLATION
PABF3B	3.90E-04	5.98E-09	0.03%	PAB FLOOD AT EL 722 TRN B - EARLY ISOLATION

Table 5

Unit 1 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
PABF4A	3.32E-05	1.12E-09	0.00%	PAB FLOOD AT EL 722 TRN A - LATE ISOLATION
PABF4B	3.32E-05	6.66E-10	0.00%	PAB FLOOD AT EL 722 TRN B - LATE ISOLATION
PABF5A	1.68E-06	6.09E-11	0.00%	PAB FLOOD AT EL 722 TRN A - NOT ISOLATED
PABF5B	1.68E-06	4.35E-11	0.00%	PAB FLOOD AT EL 722 TRN B - NOT ISOLATED
TBFL	7.71E-03	7.45E-08	0.32%	TURBINE BUILDING FLOOD
		6.89E-07	**2.93%**	**INTERNAL FLOODS TOTAL**
ELOCA	2.66E-07	2.66E-07	1.13%	EXCESSIVE LOSS OF COOLANT ACCIDENT
LLOCAA	2.40E-06	3.54E-09	0.02%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP A
LLOCAB	2.40E-06	3.54E-09	0.02%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP B
LLOCAC	2.40E-06	3.54E-09	0.02%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP C
MLOCAA	2.03E-05	4.20E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP A
MLOCAB	2.03E-05	4.20E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP B
MLOCAC	2.03E-05	4.20E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP C
SLOCI	7.26E-04	7.31E-10	0.00%	SMALL LOCA, ISOLABLE
SLOCN	2.68E-03	1.12E-07	0.48%	SMALL LOCA, NONISOLABLE
SGTRA	1.48E-03	4.07E-07	1.73%	STEAM GENERATOR A TUBE RUPTURE
SGTRB	1.48E-03	4.07E-07	1.73%	STEAM GENERATOR B TUBE RUPTURE
SGTRC	1.48E-03	4.07E-07	1.73%	STEAM GENERATOR C TUBE RUPTURE
VSX	1.07E-05	8.00E-08	0.34%	INTERFACING SYSTEMS LOCA (V-SEQUENCE)
		1.82E-06	**7.73%**	**LOCAS TOTAL**
AOX	2.04E-02	6.61E-07	2.81%	LOSS OF EMERGENCY AC ORANGE POWER
BPX	2.04E-02	4.16E-07	1.77%	LOSS OF EMERGENCY 4160V AC PURPLE
DOX	3.38E-02	5.17E-07	2.20%	LOSS OF EMERGENCY 125V DC ORANGE
DPX	3.38E-02	7.84E-07	3.34%	LOSS OF EMERGENCY 125V DC PURPLE
IBX	6.00E-03	3.29E-09	0.01%	LOSS OF VITAL BUS III (BLUE)
IRX	6.00E-03	2.41E-08	0.10%	VITAL BUS 1 INITIATING EVENT
IWX	6.00E-03	1.50E-08	0.06%	VITAL BUS 2 INITIATING EVENT
IYX	6.00E-03	3.28E-09	0.01%	LOSS OF VITAL BUS IV (YELLOW)
LB1A	3.85E-03	3.46E-08	0.15%	LOSS OF NORMAL 4KV BUS 1A
LB1D	3.52E-03	2.09E-08	0.09%	LOSS OF NORMAL 4KV BUS 1D
LOSP	3.16E-02	2.87E-07	1.22%	LOSS OF OFFSITE POWER
		2.77E-06	**11.77%**	**AC/DC POWER LOSSES TOTAL**
SEIS1	1.42E-04	4.50E-07	1.92%	SEISMIC PGA (0.10 - 0.25 G)
SEIS2	1.70E-05	3.00E-06	12.75%	SEISMIC PGA (0.25 - 0.35 G)
SEIS3	8.36E-06	5.25E-06	22.34%	SEISMIC PGA (0.35 - 0.50 G)
SEIS4	2.93E-06	2.93E-06	12.44%	SEISMIC PGA (0.50 - 1.00 G)
SEIS5	7.57E-08	7.50E-08	0.32%	SEISMIC PGA (1.00 - 1.33 G)
		1.17E-05	**49.77%**	**EARTHQUAKES TOTAL**
AMSIV	1.45E-02	3.63E-09	0.02%	CLOSURE OF ALL MSIV'S
BVX	1.86E-07	5.27E-09	0.02%	LOSS OF EMERGENCY SWITCHGEAR VENTILATION

Table 5

Unit 1 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
CCX	3.14E-03	1.12E-08	0.05%	LOSS OF REACTOR COMPONENT COOLING WATER
CPEXC	1.18E-02	1.95E-09	0.01%	CORE POWER EXCURSION
EXFW	1.90E-01	3.30E-08	0.14%	EXCESSIVE FEEDWATER FLOW
IAX	7.89E-02	7.40E-07	3.15%	LOSS OF STATION INSTRUMENT AIR
ICX	1.25E-02	4.46E-08	0.19%	CNMT INSTRUMENT AIR INITIATING EVENT
IMSIV	1.89E-01	9.52E-08	0.40%	CLOSURE OF ONE MSIV
ISI	9.56E-02	4.77E-08	0.20%	INADVERTANT SAFETY INJECTION INITIATION
LCV	1.34E-01	2.31E-08	0.10%	LOSS OF CONDENSER VACUUM
LOPF	9.09E-02	1.54E-08	0.07%	LOSS OF PRIMARY FLOW
MFWLB	2.62E-03	9.52E-10	0.00%	MAIN FEEDWATER LINE BREAK
MSV	9.76E-04	4.81E-10	0.00%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING
PLMFW	5.88E-01	1.03E-07	0.44%	PARTIAL LOSS OF MAIN FEEDWATER
RTRIP	8.39E-01	1.48E-07	0.63%	REACTOR TRIP
SLBC	1.54E-03	8.69E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE
SLBD	4.58E-03	3.11E-09	0.01%	STEAM LINE BREAK OUTSIDE CONTAINMENT
SLBI	8.49E-04	4.43E-09	0.02%	STEAMLINE BREAK INSIDE CONTAINMENT
TLMFW	4.85E-02	1.68E-08	0.07%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIP	7.17E-01	1.30E-07	0.55%	TURBINE TRIP
WCX	3.80E-06	2.67E-07	1.14%	LOSS OF RIVER WATER HEADERS A & B
		1.70E-06	**7.22%**	**TRANSIENTS TOTAL**

Table 6

Unit 1 - Case 1 Sequence Type Contribution

Sequence Type	Frequency	Percentage
Seismic Events	1.17E-05	49.77%
Internal Fires	4.69E-06	19.95%
Loss of Emergency DC Power	1.30E-06	5.54%
Steam Generator Tube Rupture	1.22E-06	5.20%
Loss of Emergency AC Power	1.08E-06	4.58%
Loss of Station Air	7.40E-07	3.15%
Internal Floods	6.89E-07	2.93%
Loss of Offsite Power	2.87E-07	1.22%
Loss of River Water	2.67E-07	1.14%
Excessive LOCA	2.66E-07	1.13%
Other Sequence Types	1.88E-07	0.80%
Reactor Trip	1.48E-07	0.63%
ATWS	1.48E-07	0.63%
Turbine Trip	1.30E-07	0.55%
Medium LOCA	1.26E-07	0.54%
Non-Isolable Small LOCA	1.12E-07	0.48%
Partial Loss of MFW	1.03E-07	0.44%
Interfacing Systems LOCA	8.00E-08	0.34%
Loss Of Normal AC Power	5.55E-08	0.24%
Inadvertent Safety Injection	4.77E-08	0.20%
Loss of Containment Air	4.46E-08	0.19%
Excessive MFW	3.30E-08	0.14%
Loss of Condenser Vacuum	2.31E-08	0.10%
Total Loss of MFW	1.68E-08	0.07%
Large LOCA	1.06E-08	0.05%
Isolable Small LOCA	7.31E-10	0.00%

Table 7

Unit 1 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
AMSIVA	1.45E-02	2.74E-11	0.00%	CLOSURE OF ALL MSIV'S - ATWS
AOXA	2.04E-02	1.85E-09	0.01%	LOSS OF EMERGENCY 4160V AC ORANGE - ATWS
BPXA	2.04E-02	2.04E-09	0.01%	LOSS OF EMERGENCY 4160V AC PURPLE - ATWS
CCXA	3.14E-03	4.00E-12	0.00%	LOSS OF REACTOR COMPONENT COOLING WATER - ATWS
DOXA	3.38E-02	1.30E-08	0.05%	LOSS OF EMERGENCY 125V DC ORANGE - ATWS
DPXA	3.38E-02	5.96E-09	0.03%	LOSS OF EMERGENCY 125V DC PURPLE-ATWS
EXFWA	1.90E-01	1.44E-08	0.06%	EXCESSIVE FEEDWATER FLOW - ATWS
IAXA	7.89E-02	6.07E-09	0.03%	LOSS OF STATION INSTRUMENT AIR - ATWS
IBXA	6.00E-03	3.02E-09	0.01%	LOSS OF VITAL BUS III (BLUE) - ATWS
ICXA	1.25E-02	2.37E-11	0.00%	CNMT INST AIR INITIATING EVENT - ATWS
IMSIVA	1.89E-01	1.41E-08	0.06%	CLOSURE OF ONE MSIV - ATWS
IRXA	6.00E-03	9.80E-11	0.00%	LOSS OF VITAL BUS I (RED) - ATWS
ISIA	9.56E-02	7.09E-09	0.03%	INADVERTANT SAFETY INJECTION INITIATION - ATWS
IWXA	6.00E-03	1.02E-10	0.00%	LOSS OF VITAL BUS II (WHITE) - ATWS
IYXA	6.00E-03	2.11E-09	0.01%	LOSS OF VITAL BUS IV (YELLOW) - ATWS
LB1AA	3.85E-03	5.90E-11	0.00%	LOSS OF NORMAL 4KV BUS 1A - ATWS
LB1DA	3.52E-03	5.13E-11	0.00%	LOSS OF NORMAL 4KV BUS 1D - ATWS
LCVA	1.34E-01	3.03E-10	0.00%	LOSS OF CONDENSER VACUUM - ATWS
LOSPA	3.16E-02	9.14E-09	0.04%	LOSS OF OFFSITE POWER - ATWS
LOPFA	9.09E-02	1.99E-10	0.00%	LOSS OF PRIMARY FLOW - ATWS
MFWLBA	2.62E-03	1.84E-10	0.00%	MAIN FEEDWATER LINE BREAK - ATWS
MSVA	9.76E-04	1.12E-10	0.00%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING - ATWS
PLMFWA	5.88E-01	4.47E-08	0.19%	PARTIAL LOSS OF MAIN FEEDWATER - ATWS
SGTRAA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR A TUBE RUPTURE - ATWS
SGTRBA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR B TUBE RUPTURE - ATWS
SGTRCA	1.48E-03	5.66E-09	0.02%	STEAM GENERATOR C TUBE RUPTURE - ATWS
SLBIA	8.49E-04	1.04E-10	0.00%	STEAMLINE BREAK INSIDE CONTAINMENT - ATWS
SLBCA	1.54E-03	1.81E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE - ATWS
SLBDA	4.58E-03	5.54E-10	0.00%	STEAM LINE BREAK OUTSIDE CONTAINMENT - ATWS
TLMFWA	4.85E-02	3.63E-09	0.02%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIPA	7.17E-01	1.75E-09	0.01%	TURBINE TRIP - ATWS
WCXA	3.80E-06	1.25E-11	0.00%	LOSS OF RIVER WATER HEADERS A & B - ATWS
		1.48E-07	**0.62%**	**ATWS TOTAL**
AF1L1C	1.31E-06	2.92E-11	0.00%	DETAILED FIRE SCENARIO AF1-L-1C
CR1L1A	3.10E-05	1.79E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1A

Table 7

Unit 1 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
CR1L1B	2.95E-05	1.70E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1B
CR1L1C	4.57E-05	3.21E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1C
CR1L1D	4.27E-05	2.90E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1D
CR1L1F	2.95E-05	1.70E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1F
CR1L1G	9.14E-05	6.95E-11	0.00%	DETAILED FIRE SCENARIO CR1-L-1G
CR1L1O	5.71E-06	8.18E-08	0.34%	DETAILED FIRE SCENARIO CR1-L-1O
CR1L1P	1.47E-05	2.11E-07	0.89%	DETAILED FIRE SCENARIO CR1-L-1P
CR1L1Q	3.54E-06	5.07E-08	0.21%	DETAILED FIRE SCENARIO CR1-L-1Q
CR1L1S	1.62E-06	5.02E-08	0.21%	DETAILED FIRE SCENARIO CR1-L-1S
CR3L1E	8.78E-07	6.17E-08	0.26%	DETAILED FIRE SCENARIO CR3-L-1E
CR3L1F	8.61E-06	3.54E-12	0.00%	DETAILED FIRE SCENARIO CR3-L-1F
CR3L1G	8.10E-07	5.69E-08	0.24%	DETAILED FIRE SCENARIO CR3-L-1G
CR3P1A	2.47E-07	1.73E-08	0.07%	DETAILED FIRE SCENARIO CR3-P-1A
CR4L1A	2.22E-04	1.91E-10	0.00%	DETAILED FIRE SCENARIO CR4-L-1A
CR4L1C	1.90E-07	1.90E-07	0.80%	DETAILED FIRE SCENARIO CR4-L-1C
CR4L1D	1.13E-07	1.13E-07	0.48%	DETAILED FIRE SCENARIO CR4-L-1D
CR4L1E	5.65E-07	3.96E-08	0.17%	DETAILED FIRE SCENARIO CR4-L-1E
CR4L1O	2.74E-07	1.92E-08	0.08%	DETAILED FIRE SCENARIO CR4-L-1O
CR4L1P	8.01E-08	8.00E-08	0.34%	DETAILED FIRE SCENARIO CR4-L-1P
CRL1AC	2.89E-05	1.62E-09	0.01%	DETAILED FIRE SCENARIO CR1-L-1AC
CRL1AP	2.89E-05	1.36E-09	0.01%	DETAILED FIRE SCENARIO CR1-L-1AP
CRL1EB	4.93E-05	1.11E-09	0.00%	DETAILED FIRE SCENARIO CR1-L-1EB
CRP1AE	5.34E-05	2.93E-08	0.12%	DETAILED FIRE SCENARIO CR1-P-1AE
CS1L1A	3.95E-05	2.59E-11	0.00%	DETAILED FIRE SCENARIO CS1-L-1A
CS1L1B	5.39E-06	4.26E-07	1.79%	DETAILED FIRE SCENARIO CS1-L-1B
CS1L1C	3.23E-05	2.55E-06	10.76%	DETAILED FIRE SCENARIO CS1-L-1C
CS1L1D	1.07E-04	8.35E-11	0.00%	DETAILED FIRE SCENARIO CS1-L-1D
CS1L1E	1.80E-06	1.27E-07	0.53%	DETAILED FIRE SCENARIO CS1-L-1E
CS1L1F	2.05E-07	1.43E-08	0.06%	DETAILED FIRE SCENARIO CS1-L-1F
CV1L1A	1.20E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1A
CV1L1B	8.12E-06	1.71E-10	0.00%	DETAILED FIRE SCENARIO CV1-L-1B
CV1L1D	7.46E-06	2.08E-12	0.00%	DETAILED FIRE SCENARIO CV1-L-1D
CV1L1G	1.14E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1G
CV1L1H	7.26E-07	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV1-L-1H
CV2L1A	7.02E-06	1.96E-12	0.00%	DETAILED FIRE SCENARIO CV2-L-1A
CV2L1E	1.20E-06	0.00E+00	0.00%	DETAILED FIRE SCENARIO CV2-L-1E
CV2L1F	1.47E-05	7.06E-12	0.00%	DETAILED FIRE SCENARIO CV2-L-1F
CV3L1A	3.11E-06	2.19E-07	0.92%	DETAILED FIRE SCENARIO CV3-L-1A
CV3L1B	1.16E-06	8.15E-08	0.34%	DETAILED FIRE SCENARIO CV3-L-1B
DG1L1A	9.08E-03	5.20E-08	0.22%	DETAILED FIRE SCENARIO DG1-L-1A

Table 7

Unit 1 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
DG2L1A	9.00E-03	5.12E-08	0.22%	DETAILED FIRE SCENARIO DG2-L-1A
ES1AE1	1.40E-04	1.89E-08	0.08%	DETAILED FIRE SCENARIO ES1AE-L-1
ES1DF1	1.61E-04	1.37E-08	0.06%	DETAILED FIRE SCENARIO ES1DF-L-1
NS1L1B	1.83E-07	1.28E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1B
NS1L1G	4.57E-08	3.17E-09	0.01%	DETAILED FIRE SCENARIO NS1-L-1G
NS1L1I	4.57E-08	3.17E-09	0.01%	DETAILED FIRE SCENARIO NS1-L-1I
NS1L1J	1.84E-07	1.29E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1J
NS1L1K	2.75E-07	1.93E-08	0.08%	DETAILED FIRE SCENARIO NS1-L-1K
NS1L1L	2.75E-07	1.93E-08	0.08%	DETAILED FIRE SCENARIO NS1-L-1L
NS1L1M	1.84E-07	1.29E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1M
NS1L1Q	1.80E-07	1.26E-08	0.05%	DETAILED FIRE SCENARIO NS1-L-1Q
PA1ELC	6.43E-07	7.12E-09	0.03%	DETAILED FIRE SCENARIO PA1E-L-1C
PA1ELE	6.43E-07	7.12E-09	0.03%	DETAILED FIRE SCENARIO PA1E-L-1E
PA1ELF	4.29E-07	4.74E-09	0.02%	DETAILED FIRE SCENARIO PA1E-L-1F
PA1ELG	1.07E-07	1.17E-09	0.00%	DETAILED FIRE SCENARIO PA1E-L-1G
PA1ELH	2.14E-07	2.36E-09	0.01%	DETAILED FIRE SCENARIO PA1E-L-1H
PA1ELI	2.14E-07	2.36E-09	0.01%	DETAILED FIRE SCENARIO PA1E-L-1I
PA1ELM	6.09E-08	6.62E-10	0.00%	DETAILED FIRE SCENARIO PA1E-L-1M
PA1GDB	2.54E-05	1.47E-11	0.00%	DETAILED FIRE SCENARIO PA1GD-L-1B
PA1GDH	9.03E-06	1.12E-09	0.00%	DETAILED FIRE SCENARIO PA1GD-L-1H
PNAP1A	1.14E-04	1.07E-10	0.00%	DETAILED FIRE SCENARIO PNA-P-1A
PT1ALA	1.44E-04	1.30E-10	0.00%	DETAILED FIRE SCENARIO PT1A-L-A
PT1APA	2.22E-05	1.19E-11	0.00%	DETAILED FIRE SCENARIO PT1A-P-1A
RC1L1	1.46E-02	2.50E-08	0.11%	DETAILED FIRE SCENARIO RC1-L-1
TB1ALA	2.39E-04	4.27E-09	0.02%	DETAILED FIRE SCENARIO TB1A-L-1A
TG1P1A	1.47E-04	2.61E-09	0.01%	DETAILED FIRE SCENARIO TG1-P-1A
		4.71E-06	**19.87%**	**INTERNAL FIRES TOTAL**
CRFL	3.29E-06	1.95E-09	0.01%	FLOOD IN CONTROL BLDG HVAC ROOM
CVFL	1.50E-04	1.50E-11	0.00%	WEST CABLE VAULT FLOOD
ISFLA	9.01E-04	3.65E-09	0.02%	INTAKE STRUCTURE FLOOD IN CUBICLE A
ISFLB	6.76E-04	2.83E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE B
ISFLC	6.76E-04	2.10E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE C
ISFLD	1.13E-03	1.57E-10	0.00%	INTAKE STRUCTURE FLOOD IN CUBICLE C
PABF1A	3.85E-04	1.45E-08	0.06%	PAB FLOOD AT EL 735 RW TRN A - ISOLATED
PABF1B	3.85E-04	8.90E-09	0.04%	PAB FLOOD AT EL 735 RW TRN B - ISOLATED
PABF2A	2.53E-05	2.83E-07	1.19%	PAB FLOOD AT EL 735 TRN A - NOT ISOLATED
PABF2B	2.53E-05	2.83E-07	1.19%	PAB FLOOD AT EL 735 TRN B - NOT ISOLATED
PABF3A	3.90E-04	1.25E-08	0.05%	PAB FLOOD AT EL 722 TRN A - EARLY ISOLATION
PABF3B	3.90E-04	6.41E-09	0.03%	PAB FLOOD AT EL 722 TRN B - EARLY

Table 7

Unit 1 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
				ISOLATION
PABF4A	3.32E-05	1.16E-09	0.00%	PAB FLOOD AT EL 722 TRN A - LATE ISOLATION
PABF4B	3.32E-05	7.00E-10	0.00%	PAB FLOOD AT EL 722 TRN B - LATE ISOLATION
PABF5A	1.68E-06	6.44E-11	0.00%	PAB FLOOD AT EL 722 TRN A - NOT ISOLATED
PABF5B	1.68E-06	4.55E-11	0.00%	PAB FLOOD AT EL 722 TRN B - NOT ISOLATED
TBFL	7.71E-03	7.47E-08	0.32%	TURBINE BUILDING FLOOD
		6.91E-07	**2.91%**	**INTERNAL FLOODS TOTAL**
ELOCA	2.66E-07	2.66E-07	1.12%	EXCESSIVE LOSS OF COOLANT ACCIDENT
LLOCAA	2.40E-06	3.55E-09	0.01%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP A
LLOCAB	2.40E-06	3.55E-09	0.01%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP B
LLOCAC	2.40E-06	3.55E-09	0.01%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP C
MLOCAA	2.03E-05	4.21E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP A
MLOCAB	2.03E-05	4.21E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP B
MLOCAC	2.03E-05	4.21E-08	0.18%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP C
SLOCI	7.26E-04	7.73E-10	0.00%	SMALL LOCA, ISOLABLE
SLOCN	2.68E-03	1.12E-07	0.47%	SMALL LOCA, NONISOLABLE
SGTRA	1.48E-03	4.07E-07	1.72%	STEAM GENERATOR A TUBE RUPTURE
SGTRB	1.48E-03	4.07E-07	1.72%	STEAM GENERATOR B TUBE RUPTURE
SGTRC	1.48E-03	4.07E-07	1.72%	STEAM GENERATOR C TUBE RUPTURE
VSX	1.07E-05	8.07E-08	0.34%	INTERFACING SYSTEMS LOCA (V-SEQUENCE)
		1.82E-06	**7.67%**	**LOCAS TOTAL**
AOX	2.04E-02	6.92E-07	2.92%	LOSS OF EMERGENCY AC ORANGE POWER
BPX	2.04E-02	4.44E-07	1.87%	LOSS OF EMERGENCY 4160V AC PURPLE
DOX	3.38E-02	5.50E-07	2.32%	LOSS OF EMERGENCY 125V DC ORANGE
DPX	3.38E-02	8.29E-07	3.50%	LOSS OF EMERGENCY 125V DC PURPLE
IBX	6.00E-03	3.30E-09	0.01%	LOSS OF VITAL BUS III (BLUE)
IRX	6.00E-03	2.49E-08	0.11%	VITAL BUS 1 INITIATING EVENT
IWX	6.00E-03	1.59E-08	0.07%	VITAL BUS 2 INITIATING EVENT
IYX	6.00E-03	3.29E-09	0.01%	LOSS OF VITAL BUS IV (YELLOW)
LB1A	3.85E-03	3.70E-08	0.16%	LOSS OF NORMAL 4KV BUS 1A
LB1D	3.52E-03	2.21E-08	0.09%	LOSS OF NORMAL 4KV BUS 1D
LOSP	3.16E-02	3.14E-07	1.33%	LOSS OF OFFSITE POWER
		2.94E-06	**12.38%**	**AC/DC POWER LOSSES TOTAL**
SEIS1	1.42E-04	4.51E-07	1.90%	SEISMIC PGA (0.10 - 0.25 G)
SEIS2	1.70E-05	3.00E-06	12.65%	SEISMIC PGA (0.25 - 0.35 G)
SEIS3	8.36E-06	5.25E-06	22.14%	SEISMIC PGA (0.35 - 0.50 G)
SEIS4	2.93E-06	2.93E-06	12.33%	SEISMIC PGA (0.50 - 1.00 G)
SEIS5	7.57E-08	7.50E-08	0.32%	SEISMIC PGA (1.00 - 1.33 G)
		1.17E-05	**49.34%**	**EARTHQUAKES TOTAL**
AMSIV	1.45E-02	3.80E-09	0.02%	CLOSURE OF ALL MSIV'S

Table 7

Unit 1 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
BVX	1.86E-07	5.27E-09	0.02%	LOSS OF EMERGENCY SWITCHGEAR VENTILATION
CCX	3.14E-03	1.12E-08	0.05%	LOSS OF REACTOR COMPONENT COOLING WATER
CPEXC	1.18E-02	1.97E-09	0.01%	CORE POWER EXCURSION
EXFW	1.90E-01	3.35E-08	0.14%	EXCESSIVE FEEDWATER FLOW
IAX	7.89E-02	7.41E-07	3.12%	LOSS OF STATION INSTRUMENT AIR
ICX	1.25E-02	4.46E-08	0.19%	CNMT INSTRUMENT AIR INITIATING EVENT
IMSIV	1.89E-01	9.78E-08	0.41%	CLOSURE OF ONE MSIV
ISI	9.56E-02	4.90E-08	0.21%	INADVERTANT SAFETY INJECTION INITIATION
LCV	1.34E-01	2.34E-08	0.10%	LOSS OF CONDENSER VACUUM
LOPF	9.09E-02	1.56E-08	0.07%	LOSS OF PRIMARY FLOW
MFWLB	2.62E-03	9.55E-10	0.00%	MAIN FEEDWATER LINE BREAK
MSV	9.76E-04	4.89E-10	0.00%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING
PLMFW	5.88E-01	1.05E-07	0.44%	PARTIAL LOSS OF MAIN FEEDWATER
RTRIP	8.39E-01	1.50E-07	0.63%	REACTOR TRIP
SLBC	1.54E-03	8.83E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE
SLBD	4.58E-03	3.23E-09	0.01%	STEAM LINE BREAK OUTSIDE CONTAINMENT
SLBI	8.49E-04	4.44E-09	0.02%	STEAMLINE BREAK INSIDE CONTAINMENT
TLMFW	4.85E-02	1.79E-08	0.08%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIP	7.17E-01	1.32E-07	0.56%	TURBINE TRIP
WCX	3.80E-06	2.67E-07	1.13%	LOSS OF RIVER WATER HEADERS A & B
		1.71E-06	**7.20%**	**TRANSIENTS TOTAL**

Table 8

Unit 1 - Case 2 Sequence Type Contribution

Sequence Type	Frequency	Percentage
Seismic Events	1.17E-05	49.34%
Internal Fires	4.71E-06	19.87%
Loss of Emergency DC Power	1.38E-06	5.82%
Steam Generator Tube Rupture	1.22E-06	5.15%
Loss of Emergency AC Power	1.14E-06	4.79%
Loss of Station Air	7.41E-07	3.12%
Internal Floods	6.91E-07	2.91%
Loss of Offsite Power	3.14E-07	1.33%
Loss of River Water	2.67E-07	1.13%
Excessive LOCA	2.66E-07	1.12%
Other Sequence Types	1.93E-07	0.81%
Reactor Trip	1.50E-07	0.63%
ATWS	1.48E-07	0.62%
Turbine Trip	1.32E-07	0.56%
Medium LOCA	1.26E-07	0.53%
Non-Isolable Small LOCA	1.12E-07	0.47%
Partial Loss of MFW	1.05E-07	0.44%
Interfacing Systems LOCA	8.07E-08	0.34%
Loss Of Normal AC Power	5.91E-08	0.25%
Inadvertent Safety Injection	4.90E-08	0.21%
Loss of Containment Air	4.46E-08	0.19%
Excessive MFW	3.35E-08	0.14%
Loss of Condenser Vacuum	2.34E-08	0.10%
Total Loss of MFW	1.79E-08	0.08%
Large LOCA	1.07E-08	0.04%
Isolable Small LOCA	7.73E-10	0.00%

Table 9

Unit 2 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
AMSIVA	5.15E-03	7.71E-11	0.00%	CLOSURE OF ALL MSIV'S - ATWS
AOXA	1.69E-02	2.08E-09	0.01%	LOSS OF EMERGENCY 4160V AC ORANGE - ATWS
BPXA	1.70E-02	1.20E-09	0.00%	LOSS OF EMERGENCY 4160V AC PURPLE - ATWS
CCXA	7.34E-03	1.14E-10	0.00%	LOSS OF PRIMARY COMPONENT COOLING WATER - ATWS
CPEXCA	1.28E-02	2.13E-10	0.00%	CORE POWER EXCURSION - ATWS
DOXA	6.34E-03	6.12E-10	0.00%	LOSS OF EMERGENCY 125V DC ORANGE - ATWS
DPXA	6.31E-03	7.18E-09	0.02%	LOSS OF EMERGENCY 125V DC PURPLE
EXFWA	1.04E-01	4.21E-08	0.13%	EXCESSIVE FEEDWATER FLOW - ATWS
IAXA	7.76E-02	3.13E-08	0.10%	LOSS OF STATION INSTRUMENT AIR SUPPLY - ATWS
IBXA	6.23E-03	8.14E-09	0.02%	LOSS OF VITAL BUS III (BLUE) - ATWS
ICXA	8.70E-02	1.58E-09	0.00%	LOSS OF CONTAINMENT INSTRUMENT AIR SUPPLY - ATWS
IMSIVA	4.94E-02	1.93E-08	0.06%	CLOSURE OF ONE MSIV - ATWS
IRXA	6.23E-03	7.25E-10	0.00%	LOSS OF VITAL BUS I (RED) - ATWS
ISIA	4.30E-02	1.67E-08	0.05%	INADVERTANT SAFETY INJECTION INIT - ATWS
IWXA	6.23E-03	7.07E-10	0.00%	LOSS OF VITAL BUS II (WHITE) - ATWS
IYXA	6.23E-03	6.92E-09	0.02%	LOSS OF VITAL BUS IV (YELLOW) - ATWS
LB2AA	7.70E-03	1.65E-10	0.00%	LOSS OF 4160V BUS 2A - ATWS
LB2DA	6.94E-03	1.65E-10	0.00%	LOSS OF 4160V BUS 2D - ATWS
LCVA	1.58E-02	6.32E-09	0.02%	LOSS OF CONDENSER VACUUM - ATWS
LOSPA	2.31E-02	6.07E-09	0.02%	LOSS OF OFFSITE POWER - ATWS
LPRFA	4.51E-02	8.07E-10	0.00%	LOSS OF PRIMARY FLOW - ATWS
MFWLBA	2.79E-03	1.06E-09	0.00%	MAIN FEEDWATER LINE BREAK - ATWS
MSVA	1.03E-03	4.93E-10	0.00%	MAIN STEAM RELIEF/SAFETY VALVE OPENS - ATWS
PLMFWA	2.50E-01	1.01E-07	0.31%	PARTIAL LOSS OF MAIN FEEDWATER - ATWS
SGTRAA	1.61E-03	7.66E-10	0.00%	A STEAM GENERATOR TUBE RUPTURE - ATWS
SGTRBA	1.61E-03	7.66E-10	0.00%	B STEAM GENERATOR TUBE RUPTURE - ATWS
SGTRCA	1.61E-03	7.66E-10	0.00%	C STEAM GENERATOR TUBE RUPTURE - ATWS
SLB1A	8.69E-04	4.29E-10	0.00%	STEAM LINE BREAK INSIDE CONTAINMENT - ATWS
SLBCA	1.62E-03	7.81E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE - ATWS
SLBDA	4.90E-03	2.37E-09	0.01%	STEAM LINE BREAK OUTSIDE CONTAINMENT - ATWS
TLMFWA	6.26E-02	2.53E-08	0.08%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIPA	5.56E-01	1.03E-08	0.03%	TURBINE/GENERATOR TRIP - ATWS
WAXA	3.21E-03	8.17E-11	0.00%	LOSS OF SERVICE WATER TRAIN A - ATWS
WBXA	2.46E-03	5.93E-11	0.00%	LOSS OF SERVICE WATER TRAIN B - ATWS

Table 9

Unit 2 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
WCXA	5.31E-08	0.00E+00	0.00%	LOSS OF BOTH TRAINS A & B SERVICE SWTER - ATWS
		2.97E-07	**0.90%**	**ATWS TOTAL**
CB1L1G	4.63E-05	2.18E-08	0.07%	FIRE SUB SCENARIO CB1L1G
CB1L1H	2.15E-06	3.37E-09	0.01%	FIRE SUB SCENARIO CB1L1H
CB1P1A	2.51E-07	2.51E-07	0.76%	FIRE SUB SCENARIO CB1P1A
CB2L1A	4.28E-05	3.99E-10	0.00%	FIRE SUB SCENARIO CB2L1A
CB3L1E	5.99E-05	2.70E-09	0.01%	FIRE SUB SCENARIO CB3L1EB
CB3L1F	3.59E-05	1.59E-09	0.00%	FIRE SUB SCENARIO CB3L1F
CB3L1O	6.86E-06	2.64E-07	0.80%	FIRE SUB SCENARIO CB3L1O
CB3L1P	1.76E-05	6.78E-07	2.06%	FIRE SUB SCENARIO CB3L1P
CB3L1Q	4.31E-06	1.66E-07	0.50%	FIRE SUB SCENARIO CB3L1Q
CB3L1S	1.98E-06	1.45E-07	0.44%	FIRE SUB SCENARIO CB3L1S
CB3P1A	6.50E-05	9.77E-09	0.03%	FIRE SUB SCENARIO CB3P1AE
CT1L1A	5.08E-07	5.08E-07	1.54%	FIRE SUB SCENARIO CT1L1A
CT1L1B	3.05E-07	3.05E-07	0.93%	FIRE SUB SCENARIO CT1L1B
CT1L1C	9.18E-05	9.99E-08	0.30%	FIRE SUB SCENARIO CT1L1C
CT1L1D	7.14E-05	4.10E-08	0.12%	FIRE SUB SCENARIO CT1L1D
CT1P1A	1.54E-07	1.54E-07	0.47%	FIRE SUB SCENARIO CT1P1AA
CT1P2A	1.54E-07	1.54E-07	0.47%	FIRE SUB SCENARIO CT1P2A
CV1L1A	1.74E-04	1.07E-09	0.00%	FIRE SUB SCENARIO CV1L1A
CV1L1B	1.74E-04	1.07E-09	0.00%	FIRE SUB SCENARIO CV1L1B
CV1L1F	5.58E-05	3.03E-10	0.00%	FIRE SUB SCENARIO CV1L1F
CV2L1A	1.74E-04	4.80E-10	0.00%	FIRE SUB SCENARIO CV2L1A
CV3L1A	1.25E-04	9.32E-08	0.28%	FIRE SUB SCENARIO CV3L1A
CV3L1E	1.81E-04	1.35E-07	0.41%	FIRE SUB SCENARIO CV3L1E
CV3L1F	1.81E-04	2.23E-07	0.68%	FIRE SUB SCENARIO CV3L1F
DG1L1A	1.04E-02	3.68E-07	1.12%	FIRE SUB SCENARIO DG1L1A
DG2L1A	1.03E-02	3.64E-07	1.11%	FIRE SUB SCENARIO DG2L1A
PA4L1K	1.45E-04	5.28E-09	0.02%	FIRE SUB SCENARIO PA4L1K
PA4L1Q	3.63E-05	1.27E-09	0.00%	FIRE SUB SCENARIO PA4L1Q
PA6L1A	1.74E-04	1.38E-09	0.00%	FIRE SUB SCENARIO PA6L1A
PA6L1C	2.04E-04	1.64E-09	0.00%	FIRE SUB SCENARIO PA6L1C
SB0P4A	2.49E-07	2.49E-07	0.76%	FIRE SUB SCENARIO SB10P4A
SB1L1B	2.47E-05	2.40E-08	0.07%	FIRE SUB SCENARIO SB1L1B
SB1L1D	1.64E-05	1.77E-08	0.05%	FIRE SUB SCENARIO SB1L1D
SB1L1E	4.66E-05	2.19E-08	0.07%	FIRE SUB SCENARIO SB1L1E
SB1L1G	2.37E-04	1.13E-07	0.34%	FIRE SUB SCENARIO SB1L1G
SB2L1A	7.81E-05	1.04E-08	0.03%	FIRE SUB SCENARIO SB2L1A
SB2L1B	2.47E-05	1.41E-08	0.04%	FIRE SUB SCENARIO SB2L1B

Table 9

Unit 2 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
SB2L1G	2.37E-04	1.21E-07	0.37%	FIRE SUB SCENARIO SB2L1G
SB4L1A	2.44E-04	6.89E-09	0.02%	FIRE SUB SCENARIO SB4L1A
SB4L1B	5.58E-04	1.60E-08	0.05%	FIRE SUB SCENARIO SB4L1B
SB4L1C	2.09E-05	5.31E-10	0.00%	FIRE SUB SCENARIO SB4L1C
SB4L1D	4.74E-04	1.20E-08	0.04%	FIRE SUB SCENARIO SB4L1D
SB4L1E	4.74E-04	1.28E-08	0.04%	FIRE SUB SCENARIO SB4L1E
SB4L1F	6.97E-06	1.78E-08	0.05%	FIRE SUB SCENARIO SB4L1F
SB4L1G	6.97E-06	1.78E-08	0.05%	FIRE SUB SCENARIO SB4L1G
SB4L1H	5.17E-06	1.32E-08	0.04%	FIRE SUB SCENARIO SB4L1H
SB4L1I	5.17E-06	1.32E-08	0.04%	FIRE SUB SCENARIO SB4L1I
SB4L1J	2.44E-04	1.10E-08	0.03%	FIRE SUB SCENARIO SB4L1J
SB4L1K	5.18E-06	1.98E-10	0.00%	FIRE SUB SCENARIO SB4L1K
SB4L1L	6.04E-06	2.33E-10	0.00%	FIRE SUB SCENARIO SB4L1L
SB4L1N	6.97E-06	2.71E-10	0.00%	FIRE SUB SCENARIO SB4L1N
SGNL1A	2.33E-04	2.14E-09	0.01%	FIRE SUB SCENARIO SGNL1A
SGNL1M	3.22E-05	1.05E-09	0.00%	FIRE SUB SCENARIO SGNL1M
SGSL1A	2.07E-04	1.13E-08	0.03%	FIRE SUB SCENARIO SGSL1A
SGSL1L	3.22E-05	1.09E-09	0.00%	FIRE SUB SCENARIO SGSL1L
		4.71E-06	**14.30%**	**INTERNAL FIRES TOTAL**
ABFL1A	6.76E-04	1.20E-08	0.04%	AUXILIARY BUILDING FLOOD, SW HDR A ISOLATED
ABFL1B	6.76E-04	1.63E-08	0.05%	AUXILIARY BUILDING FLOOD, SW HDR B ISOLATED
ABFL2A	2.19E-06	3.62E-11	0.00%	AUXILIARY BUILDING FLOOD FROM SW HDR A, NONISOLATED
ABFL2B	2.19E-06	4.35E-11	0.00%	AUXILIARY BUILDING FLOOD FROM SW HDR B, NONISOLATED
CBFL	2.96E-04	4.06E-08	0.12%	CONTROL BUILDING FLOOD
CVFLA	6.00E-06	2.20E-09	0.01%	CABLE VAULT FLOOD FROM SW HDR A
CVFLB	6.00E-06	2.23E-09	0.01%	CABLE VAULT FLOOD FROM SW HDR B
CVFLF	1.46E-04	5.30E-08	0.16%	CABLE VAULT FLOOD FROM FIRE WATER
ISFLB	6.76E-04	5.64E-09	0.02%	INTAKE STRUCTURE FLOOD CUBE B
ISFLC	6.76E-04	5.95E-09	0.02%	INTAKE STRUCTURE FLOOD CUBE C
ISFLD	1.13E-03	1.01E-08	0.03%	INTAKE STRUCTURE FLOOD CUBE D
SGFL1A	3.64E-04	2.51E-07	0.76%	S. SAFEGUARDS TRAIN A AREA FLOOD, ISOLATED
SGFL1B	3.64E-04	2.02E-08	0.06%	N. SAFEGUARDS TRAIN B AREA FLOOD, ISOLATED
SGFL2	4.88E-05	2.30E-07	0.70%	BOTH SAFEGUARDS AREA FLOOD, NONISOLATED
TBFL	7.58E-03	6.20E-08	0.19%	TURBINE BUILDING FLOOD
VPFLA	6.76E-04	1.20E-08	0.04%	SERVICE WATER VALVE PIT FLOOD, HEADER A
VPFLB	6.76E-04	1.63E-08	0.05%	SERVICE WATER VALVE PIT FLOOD, HEADER B
		7.40E-07	**2.25%**	**INTERNAL FLOODS TOTAL**

Table 9

Unit 2 - Case 1 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
ELOCA	2.66E-07	2.66E-07	0.81%	EXCESSIVE LOSS OF COOLANT ACCIDENT
LLOCAA	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP A
LLOCAB	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP B
LLOCAC	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP C
MLOCAA	2.03E-05	4.00E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP A
MLOCAB	2.03E-05	4.00E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP B
MLOCAC	2.03E-05	4.00E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP C
SGTRA	1.61E-03	3.30E-07	1.00%	A STEAM GENERATOR TUBE RUPTURE
SGTRB	1.61E-03	3.31E-07	1.00%	B STEAM GENERATOR TUBE RUPTURE
SGTRC	1.61E-03	3.30E-07	1.00%	C STEAM GENERATOR TUBE RUPTURE
SLOCI	7.87E-04	5.35E-09	0.02%	SMALL LOCA, ISOLABLE
SLOCN	2.71E-03	3.36E-07	1.02%	SMALL LOCA, NONISOLABLE
VSX	2.80E-07	2.80E-07	0.85%	INTERFACING SYSTEMS LOCA (V-SEQUENCE)
		2.03E-06	**6.17%**	**LOCAS TOTAL**
AOX	1.69E-02	5.01E-06	15.23%	LOSS OF EMERGENCY 4160V AC ORANGE
BPX	1.70E-02	4.46E-06	13.54%	LOSS OF EMERGENCY 4160V AC PURPLE
DOX	6.34E-03	5.28E-07	1.60%	LOSS OF EMERGENCY 125V DC ORANGE
DPX	6.31E-03	5.11E-07	1.55%	LOSS OF EMERGENCY 125V DC PURPLE
IBX	6.23E-03	5.39E-08	0.16%	LOSS OF VITAL BUS III (BLUE)
IRX	6.23E-03	2.95E-08	0.09%	LOSS OF VITAL BUS I (RED)
IWX	6.23E-03	2.08E-08	0.06%	LOSS OF VITAL BUS II (WHITE)
IYX	6.23E-03	5.40E-08	0.16%	LOSS OF VITAL BUS IV (YELLOW)
LB2A	7.70E-03	1.03E-07	0.31%	LOSS OF 4160V BUS 2A
LB2D	6.94E-03	7.44E-08	0.23%	LOSS OF 4160V BUS 2D
LOSP	2.31E-02	4.02E-07	1.22%	LOSS OF OFFSITE POWER
		1.12E-05	**34.16%**	**AC/DC POWER LOSSES TOTAL**
SEIS1	1.42E-04	1.76E-07	0.53%	EARTHQUAKES (0.01 - 0.25 G'S)
SEIS2	1.70E-05	1.97E-06	5.98%	EARTHQUAKES (0.25 - 0.35 G'S)
SEIS3	8.36E-06	4.43E-06	13.47%	EARTHQUAKES (0.35 - 0.50 G'S)
SEIS4	2.93E-06	2.92E-06	8.88%	EARTHQUAKES (0.50 - 1.00 G'S)
SEIS5	7.57E-08	7.55E-08	0.23%	EARTHQUAKES (1.00 - 1.33 G'S)
		9.58E-06	**29.10%**	**EARTHQUAKES TOTAL**
AMSIV	5.15E-03	3.47E-09	0.01%	CLOSURE OF ALL MSIV'S
CCX	7.34E-03	6.39E-08	0.19%	LOSS OF PRIMARY COMPONENT COOLING WATER
CPEXC	1.28E-02	9.56E-09	0.03%	CORE POWER EXCURSION
EXFW	1.04E-01	8.54E-07	2.59%	EXCESSIVE FEEDWATER FLOW
IAX	7.76E-02	6.38E-07	1.94%	LOSS OF STATION INSTRUMENT AIR SUPPLY
ICX	8.70E-02	7.50E-07	2.28%	LOSS OF CONTAINMENT INSTRUMENT AIR SUPPLY
IMSIV	4.94E-02	1.15E-07	0.35%	CLOSURE OF ONE MSIV
ISI	4.30E-02	7.98E-08	0.24%	INADVERTANT SAFETY INJECTION INITIATION

Table 9 Unit 2 - Case 1 Initiating Event CDF Contribution				
Init. Event	**I.E. Frequency**	**Core Damage Frequency**	**% of Total CDF**	**I.E. Description**
LCV	1.58E-02	1.30E-07	0.40%	LOSS OF CONDENSER VACUUM
LPRF	4.51E-02	3.44E-08	0.10%	LOSS OF PRIMARY FLOW
MFWLB	2.79E-03	2.65E-08	0.08%	MAIN FEEDWATER LINE BREAK
MSV	1.03E-03	2.60E-09	0.01%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING
PLMFW	2.50E-01	1.99E-07	0.61%	PARTIAL LOSS OF MAIN FEEDWATER
RTRIP	3.64E-01	2.55E-07	0.77%	REACTOR TRIP
SLB1	8.69E-04	1.90E-08	0.06%	STEAM LINE BREAK INSIDE CONTAINMENT
SLBC	1.62E-03	2.28E-08	0.07%	STEAM LINE BREAK IN COMMON RHS LINE
SLBD	4.90E-03	4.90E-08	0.15%	STEAM LINE BREAK OUTSIDE CONTAINMENT
TLMFW	6.26E-02	5.18E-07	1.57%	TOTAL LOSS OF MAIN FEEDWATER
TTRIP	5.56E-01	4.32E-07	1.31%	TURBINE/GENERATOR TRIP
WAX	3.21E-03	5.64E-08	0.17%	LOSS OF SERVICE WATER TRAIN A
WBXX	2.46E-03	5.77E-08	0.18%	LOSS OF SERVICE WATER TRAIN B
WCX	5.31E-08	4.00E-09	0.01%	LOSS OF SERVICE WATER TRAINS A & B
		4.32E-06	**13.12%**	**TRANSIENTS TOTAL**

Table 10 Unit 2 - Case 1 Sequence Type Contribution		
Sequence Type	**Frequency**	**Percentage**
Seismic Events	9.58E-06	29.10%
Loss of Emergency AC Power	9.47E-06	28.76%
Internal Fires	4.71E-06	14.30%
Loss of Emergency DC Power	1.04E-06	3.16%
Steam Generator Tube Rupture	9.90E-07	3.01%
Excessive MFW	8.54E-07	2.59%
Loss of Containment Air	7.50E-07	2.28%
Internal Floods	7.40E-07	2.25%
Loss of Station Air	6.38E-07	1.94%
Total Loss of MFW	5.18E-07	1.57%
Other Sequence Types	5.04E-07	1.53%
Turbine Trip	4.32E-07	1.31%
Loss of Offsite Power	4.02E-07	1.22%
Non-Isolable Small LOCA	3.36E-07	1.02%
ATWS	2.97E-07	0.90%
Interfacing Systems LOCA	2.80E-07	0.85%
Excessive LOCA	2.66E-07	0.81%
Reactor Trip	2.55E-07	0.77%
Partial Loss of MFW	1.99E-07	0.61%
Loss Of Normal AC Power	1.77E-07	0.54%
Loss of Condenser Vacuum	1.30E-07	0.40%
Medium LOCA	1.20E-07	0.36%
Loss of Service Water	1.18E-07	0.36%
Inadvertent Safety Injection	7.98E-08	0.24%
Large LOCA	3.24E-08	0.10%
Isolable Small LOCA	5.35E-09	0.02%

Table 11

Unit 2 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
AMSIVA	5.15E-03	7.71E-11	0.00%	CLOSURE OF ALL MSIV'S - ATWS
AOXA	1.69E-02	2.08E-09	0.01%	LOSS OF EMERGENCY 4160V AC ORANGE - ATWS
BPXA	1.70E-02	1.21E-09	0.00%	LOSS OF EMERGENCY 4160V AC PURPLE - ATWS
CCXA	7.34E-03	1.14E-10	0.00%	LOSS OF PRIMARY COMPONENT COOLING WATER - ATWS
CPEXCA	1.28E-02	2.13E-10	0.00%	CORE POWER EXCURSION - ATWS
DOXA	6.34E-03	6.11E-10	0.00%	LOSS OF EMERGENCY 125V DC ORANGE - ATWS
DPXA	6.31E-03	7.18E-09	0.02%	LOSS OF EMERGENCY 125V DC PURPLE
EXFWA	1.04E-01	4.21E-08	0.12%	EXCESSIVE FEEDWATER FLOW - ATWS
IAXA	7.76E-02	3.14E-08	0.09%	LOSS OF STATION INSTRUMENT AIR SUPPLY - ATWS
IBXA	6.23E-03	8.14E-09	0.02%	LOSS OF VITAL BUS III (BLUE) - ATWS
ICXA	8.70E-02	1.58E-09	0.00%	LOSS OF CONTAINMENT INSTRUMENT AIR SUPPLY - ATWS
IMSIVA	4.94E-02	1.93E-08	0.06%	CLOSURE OF ONE MSIV - ATWS
IRXA	6.23E-03	7.26E-10	0.00%	LOSS OF VITAL BUS I (RED) - ATWS
ISIA	4.30E-02	1.67E-08	0.05%	INADVERTANT SAFETY INJECTION INIT - ATWS
IWXA	6.23E-03	7.08E-10	0.00%	LOSS OF VITAL BUS II (WHITE) - ATWS
IYXA	6.23E-03	6.92E-09	0.02%	LOSS OF VITAL BUS IV (YELLOW) - ATWS
LB2AA	7.70E-03	1.74E-10	0.00%	LOSS OF 4160V BUS 2A - ATWS
LB2DA	6.94E-03	1.68E-10	0.00%	LOSS OF 4160V BUS 2D - ATWS
LCVA	1.58E-02	6.32E-09	0.02%	LOSS OF CONDENSER VACUUM - ATWS
LOSPA	2.31E-02	6.17E-09	0.02%	LOSS OF OFFSITE POWER - ATWS
LPRFA	4.51E-02	8.06E-10	0.00%	LOSS OF PRIMARY FLOW - ATWS
MFWLBA	2.79E-03	1.06E-09	0.00%	MAIN FEEDWATER LINE BREAK - ATWS
MSVA	1.03E-03	4.92E-10	0.00%	MAIN STEAM RELIEF/SAFETY VALVE OPENS - ATWS
PLMFWA	2.50E-01	1.01E-07	0.29%	PARTIAL LOSS OF MAIN FEEDWATER - ATWS
SGTRAA	1.61E-03	7.65E-10	0.00%	A STEAM GENERATOR TUBE RUPTURE - ATWS
SGTRBA	1.61E-03	7.65E-10	0.00%	B STEAM GENERATOR TUBE RUPTURE - ATWS
SGTRCA	1.61E-03	7.65E-10	0.00%	C STEAM GENERATOR TUBE RUPTURE - ATWS
SLB1A	8.69E-04	4.28E-10	0.00%	STEAM LINE BREAK INSIDE CONTAINMENT - ATWS
SLBCA	1.62E-03	7.81E-10	0.00%	STEAM LINE BREAK IN COMMON RHS LINE - ATWS
SLBDA	4.90E-03	2.37E-09	0.01%	STEAM LINE BREAK OUTSIDE CONTAINMENT - ATWS
TLMFWA	6.26E-02	2.53E-08	0.07%	TOTAL LOSS OF MAIN FEEDWATER - ATWS
TTRIPA	5.56E-01	1.03E-08	0.03%	TURBINE/GENERATOR TRIP - ATWS
WAXA	3.21E-03	8.17E-11	0.00%	LOSS OF SERVICE WATER TRAIN A - ATWS
WBXA	2.46E-03	5.93E-11	0.00%	LOSS OF SERVICE WATER TRAIN B - ATWS

Table 11

Unit 2 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
WCXA	5.31E-08	0.00E+00	0.00%	LOSS OF BOTH TRAINS A & B SERVICE SWTER - ATWS
		2.97E-07	**0.86%**	**ATWS TOTAL**
CB1L1G	4.63E-05	2.58E-08	0.07%	FIRE SUB SCENARIO CB1L1G
CB1L1H	2.15E-06	3.54E-09	0.01%	FIRE SUB SCENARIO CB1L1H
CB1P1A	2.51E-07	2.51E-07	0.73%	FIRE SUB SCENARIO CB1P1A
CB2L1A	4.28E-05	4.46E-10	0.00%	FIRE SUB SCENARIO CB2L1A
CB3L1E	5.99E-05	2.75E-09	0.01%	FIRE SUB SCENARIO CB3L1EB
CB3L1F	3.59E-05	1.62E-09	0.00%	FIRE SUB SCENARIO CB3L1F
CB3L1O	6.86E-06	2.64E-07	0.77%	FIRE SUB SCENARIO CB3L1O
CB3L1P	1.76E-05	6.78E-07	1.97%	FIRE SUB SCENARIO CB3L1P
CB3L1Q	4.31E-06	1.66E-07	0.48%	FIRE SUB SCENARIO CB3L1Q
CB3L1S	1.98E-06	1.45E-07	0.42%	FIRE SUB SCENARIO CB3L1S
CB3P1A	6.50E-05	1.13E-08	0.03%	FIRE SUB SCENARIO CB3P1AE
CT1L1A	5.08E-07	5.08E-07	1.48%	FIRE SUB SCENARIO CT1L1A
CT1L1B	3.05E-07	3.05E-07	0.89%	FIRE SUB SCENARIO CT1L1B
CT1L1C	9.18E-05	1.08E-07	0.31%	FIRE SUB SCENARIO CT1L1C
CT1L1D	7.14E-05	4.79E-08	0.14%	FIRE SUB SCENARIO CT1L1D
CT1P1A	1.54E-07	1.54E-07	0.45%	FIRE SUB SCENARIO CT1P1AA
CT1P2A	1.54E-07	1.54E-07	0.45%	FIRE SUB SCENARIO CT1P2A
CV1L1A	1.74E-04	1.31E-09	0.00%	FIRE SUB SCENARIO CV1L1A
CV1L1B	1.74E-04	1.31E-09	0.00%	FIRE SUB SCENARIO CV1L1B
CV1L1F	5.58E-05	3.76E-10	0.00%	FIRE SUB SCENARIO CV1L1F
CV2L1A	1.74E-04	6.44E-10	0.00%	FIRE SUB SCENARIO CV2L1A
CV3L1A	1.25E-04	1.05E-07	0.31%	FIRE SUB SCENARIO CV3L1A
CV3L1E	1.81E-04	1.52E-07	0.44%	FIRE SUB SCENARIO CV3L1E
CV3L1F	1.81E-04	2.40E-07	0.70%	FIRE SUB SCENARIO CV3L1F
DG1L1A	1.04E-02	4.91E-07	1.43%	FIRE SUB SCENARIO DG1L1A
DG2L1A	1.03E-02	4.87E-07	1.42%	FIRE SUB SCENARIO DG2L1A
PA4L1K	1.45E-04	7.03E-09	0.02%	FIRE SUB SCENARIO PA4L1K
PA4L1Q	3.63E-05	1.69E-09	0.00%	FIRE SUB SCENARIO PA4L1Q
PA6L1A	1.74E-04	1.62E-09	0.00%	FIRE SUB SCENARIO PA6L1A
PA6L1C	2.04E-04	1.93E-09	0.01%	FIRE SUB SCENARIO PA6L1C
SB0P4A	2.49E-07	2.49E-07	0.72%	FIRE SUB SCENARIO SB10P4A
SB1L1B	2.47E-05	2.61E-08	0.08%	FIRE SUB SCENARIO SB1L1B
SB1L1D	1.64E-05	1.91E-08	0.06%	FIRE SUB SCENARIO SB1L1D
SB1L1E	4.66E-05	2.59E-08	0.08%	FIRE SUB SCENARIO SB1L1E
SB1L1G	2.37E-04	1.33E-07	0.39%	FIRE SUB SCENARIO SB1L1G
SB2L1A	7.81E-05	1.21E-08	0.04%	FIRE SUB SCENARIO SB2L1A
SB2L1B	2.47E-05	1.65E-08	0.05%	FIRE SUB SCENARIO SB2L1B

Table 11

Unit 2 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
SB2L1G	2.37E-04	1.44E-07	0.42%	FIRE SUB SCENARIO SB2L1G
SB4L1A	2.44E-04	9.06E-09	0.03%	FIRE SUB SCENARIO SB4L1A
SB4L1B	5.58E-04	2.10E-08	0.06%	FIRE SUB SCENARIO SB4L1B
SB4L1C	2.09E-05	7.09E-10	0.00%	FIRE SUB SCENARIO SB4L1C
SB4L1D	4.74E-04	1.56E-08	0.05%	FIRE SUB SCENARIO SB4L1D
SB4L1E	4.74E-04	1.75E-08	0.05%	FIRE SUB SCENARIO SB4L1E
SB4L1F	6.97E-06	2.43E-08	0.07%	FIRE SUB SCENARIO SB4L1F
SB4L1G	6.97E-06	2.43E-08	0.07%	FIRE SUB SCENARIO SB4L1G
SB4L1H	5.17E-06	1.80E-08	0.05%	FIRE SUB SCENARIO SB4L1H
SB4L1I	5.17E-06	1.80E-08	0.05%	FIRE SUB SCENARIO SB4L1I
SB4L1J	2.44E-04	1.51E-08	0.04%	FIRE SUB SCENARIO SB4L1J
SB4L1K	5.18E-06	2.76E-10	0.00%	FIRE SUB SCENARIO SB4L1K
SB4L1L	6.04E-06	3.25E-10	0.00%	FIRE SUB SCENARIO SB4L1L
SB4L1N	6.97E-06	3.78E-10	0.00%	FIRE SUB SCENARIO SB4L1N
SGNL1A	2.33E-04	2.76E-09	0.01%	FIRE SUB SCENARIO SGNL1A
SGNL1M	3.22E-05	1.43E-09	0.00%	FIRE SUB SCENARIO SGNL1M
SGSL1A	2.07E-04	1.36E-08	0.04%	FIRE SUB SCENARIO SGSL1A
SGSL1L	3.22E-05	1.47E-09	0.00%	FIRE SUB SCENARIO SGSL1L
		5.13E-06	**14.91%**	**INTERNAL FIRES TOTAL**
ABFL1A	6.76E-04	1.39E-08	0.04%	AUXILIARY BUILDING FLOOD, SW HDR A ISOLATED
ABFL1B	6.76E-04	1.93E-08	0.06%	AUXILIARY BUILDING FLOOD, SW HDR B ISOLATED
ABFL2A	2.19E-06	4.01E-11	0.00%	AUXILIARY BUILDING FLOOD FROM SW HDR A, NONISOLATED
ABFL2B	2.19E-06	5.01E-11	0.00%	AUXILIARY BUILDING FLOOD FROM SW HDR B, NONISOLATED
CBFL	2.96E-04	4.06E-08	0.12%	CONTROL BUILDING FLOOD
CVFLA	6.00E-06	2.21E-09	0.01%	CABLE VAULT FLOOD FROM SW HDR A
CVFLB	6.00E-06	2.25E-09	0.01%	CABLE VAULT FLOOD FROM SW HDR B
CVFLF	1.46E-04	5.29E-08	0.15%	CABLE VAULT FLOOD FROM FIRE WATER
ISFLB	6.76E-04	5.71E-09	0.02%	INTAKE STRUCTURE FLOOD CUBE B
ISFLC	6.76E-04	6.07E-09	0.02%	INTAKE STRUCTURE FLOOD CUBE C
ISFLD	1.13E-03	1.03E-08	0.03%	INTAKE STRUCTURE FLOOD CUBE D
SGFL1A	3.64E-04	2.56E-07	0.75%	S. SAFEGUARDS TRAIN A AREA FLOOD, ISOLATED
SGFL1B	3.64E-04	2.03E-08	0.06%	N. SAFEGUARDS TRAIN B AREA FLOOD, ISOLATED
SGFL2	4.88E-05	2.30E-07	0.67%	BOTH SAFEGUARDS AREA FLOOD, NONISOLATED
TBFL	7.58E-03	6.22E-08	0.18%	TURBINE BUILDING FLOOD
VPFLA	6.76E-04	1.39E-08	0.04%	SERVICE WATER VALVE PIT FLOOD, HEADER A
VPFLB	6.76E-04	1.93E-08	0.06%	SERVICE WATER VALVE PIT FLOOD, HEADER B
		7.55E-07	**2.20%**	**INTERNAL FLOODS TOTAL**

Table 11

Unit 2 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
ELOCA	2.66E-07	2.66E-07	0.77%	EXCESSIVE LOSS OF COOLANT ACCIDENT
LLOCAA	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP A
LLOCAB	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP B
LLOCAC	2.40E-06	1.08E-08	0.03%	LARGE LOSS OF COOLANT ACCIDENT IN LOOP C
MLOCAA	2.03E-05	4.02E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP A
MLOCAB	2.03E-05	4.02E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP B
MLOCAC	2.03E-05	4.02E-08	0.12%	MEDIUM LOSS OF COOLANT ACCIDENT IN LOOP C
SGTRA	1.61E-03	3.30E-07	0.96%	A STEAM GENERATOR TUBE RUPTURE
SGTRB	1.61E-03	3.31E-07	0.96%	B STEAM GENERATOR TUBE RUPTURE
SGTRC	1.61E-03	3.30E-07	0.96%	C STEAM GENERATOR TUBE RUPTURE
SLOCI	7.87E-04	5.46E-09	0.02%	SMALL LOCA, ISOLABLE
SLOCN	2.71E-03	3.36E-07	0.98%	SMALL LOCA, NONISOLABLE
VSX	2.80E-07	2.80E-07	0.81%	INTERFACING SYSTEMS LOCA (V-SEQUENCE)
		2.03E-06	**5.91%**	**LOCAS TOTAL**
AOX	1.69E-02	5.38E-06	15.65%	LOSS OF EMERGENCY 4160V AC ORANGE
BPX	1.70E-02	4.87E-06	14.17%	LOSS OF EMERGENCY 4160V AC PURPLE
DOX	6.34E-03	5.59E-07	1.63%	LOSS OF EMERGENCY 125V DC ORANGE
DPX	6.31E-03	5.44E-07	1.58%	LOSS OF EMERGENCY 125V DC PURPLE
IBX	6.23E-03	5.41E-08	0.16%	LOSS OF VITAL BUS III (BLUE)
IRX	6.23E-03	2.97E-08	0.09%	LOSS OF VITAL BUS I (RED)
IWX	6.23E-03	2.09E-08	0.06%	LOSS OF VITAL BUS II (WHITE)
IYX	6.23E-03	5.41E-08	0.16%	LOSS OF VITAL BUS IV (YELLOW)
LB2A	7.70E-03	1.27E-07	0.37%	LOSS OF 4160V BUS 2A
LB2D	6.94E-03	1.00E-07	0.29%	LOSS OF 4160V BUS 2D
LOSP	2.31E-02	4.47E-07	1.30%	LOSS OF OFFSITE POWER
		1.22E-05	**35.46%**	**AC/DC POWER LOSSES TOTAL**
SEIS1	1.42E-04	1.87E-07	0.54%	EARTHQUAKES (0.01 - 0.25 G'S)
SEIS2	1.70E-05	1.98E-06	5.75%	EARTHQUAKES (0.25 - 0.35 G'S)
SEIS3	8.36E-06	4.44E-06	12.90%	EARTHQUAKES (0.35 - 0.50 G'S)
SEIS4	2.93E-06	2.92E-06	8.50%	EARTHQUAKES (0.50 - 1.00 G'S)
SEIS5	7.57E-08	7.54E-08	0.22%	EARTHQUAKES (1.00 - 1.33 G'S)
		9.60E-06	**27.92%**	**EARTHQUAKES TOTAL**
AMSIV	5.15E-03	3.57E-09	0.01%	CLOSURE OF ALL MSIV'S
CCX	7.34E-03	6.41E-08	0.19%	LOSS OF PRIMARY COMPONENT COOLING WATER
CPEXC	1.28E-02	9.82E-09	0.03%	CORE POWER EXCURSION
EXFW	1.04E-01	8.56E-07	2.49%	EXCESSIVE FEEDWATER FLOW
IAX	7.76E-02	6.40E-07	1.86%	LOSS OF STATION INSTRUMENT AIR SUPPLY
ICX	8.70E-02	7.53E-07	2.19%	LOSS OF CONTAINMENT INSTRUMENT AIR SUPPLY
IMSIV	4.94E-02	1.17E-07	0.34%	CLOSURE OF ONE MSIV
ISI	4.30E-02	8.15E-08	0.24%	INADVERTANT SAFETY INJECTION INITIATION

Table 11

Unit 2 - Case 2 Initiating Event CDF Contribution

Init. Event	I.E. Frequency	Core Damage Frequency	% of Total CDF	I.E. Description
LCV	1.58E-02	1.31E-07	0.38%	LOSS OF CONDENSER VACUUM
LPRF	4.51E-02	3.54E-08	0.10%	LOSS OF PRIMARY FLOW
MFWLB	2.79E-03	2.66E-08	0.08%	MAIN FEEDWATER LINE BREAK
MSV	1.03E-03	2.63E-09	0.01%	MAIN STEAM RELIEF OR SAFETY VALVE OPENING
PLMFW	2.50E-01	2.05E-07	0.60%	PARTIAL LOSS OF MAIN FEEDWATER
RTRIP	3.64E-01	2.62E-07	0.76%	REACTOR TRIP
SLB1	8.69E-04	1.90E-08	0.06%	STEAM LINE BREAK INSIDE CONTAINMENT
SLBC	1.62E-03	2.29E-08	0.07%	STEAM LINE BREAK IN COMMON RHS LINE
SLBD	4.90E-03	4.92E-08	0.14%	STEAM LINE BREAK OUTSIDE CONTAINMENT
TLMFW	6.26E-02	5.19E-07	1.51%	TOTAL LOSS OF MAIN FEEDWATER
TTRIP	5.56E-01	4.44E-07	1.29%	TURBINE/GENERATOR TRIP
WAX	3.21E-03	6.55E-08	0.19%	LOSS OF SERVICE WATER TRAIN A
WBXX	2.46E-03	6.86E-08	0.20%	LOSS OF SERVICE WATER TRAIN B
WCX	5.31E-08	4.00E-09	0.01%	LOSS OF SERVICE WATER TRAINS A & B
		4.38E-06	**12.74%**	**TRANSIENTS TOTAL**

Table 12 Unit 2 - Case 2 Sequence Type Contribution		
Sequence Type	**Frequency**	**Percentage**
Loss of Emergency AC Power	1.03E-05	29.82%
Seismic Events	9.60E-06	27.92%
Internal Fires	5.13E-06	14.91%
Loss of Emergency DC Power	1.10E-06	3.21%
Steam Generator Tube Rupture	9.90E-07	2.88%
Excessive MFW	8.56E-07	2.49%
Internal Floods	7.55E-07	2.20%
Loss of Containment Air	7.53E-07	2.19%
Loss of Station Air	6.40E-07	1.86%
Total Loss of MFW	5.19E-07	1.51%
Other Sequence Types	5.09E-07	1.48%
Loss of Offsite Power	4.47E-07	1.30%
Turbine Trip	4.44E-07	1.29%
Non-Isolable Small LOCA	3.36E-07	0.98%
ATWS	2.97E-07	0.86%
Interfacing Systems LOCA	2.80E-07	0.81%
Excessive LOCA	2.66E-07	0.77%
Reactor Trip	2.62E-07	0.76%
Loss Of Normal AC Power	2.27E-07	0.66%
Partial Loss of MFW	2.05E-07	0.60%
Loss of Service Water	1.38E-07	0.40%
Loss of Condenser Vacuum	1.31E-07	0.38%
Medium LOCA	1.21E-07	0.35%
Inadvertent Safety Injection	8.15E-08	0.24%
Large LOCA	3.25E-08	0.09%
Isolable Small LOCA	5.46E-09	0.02%

9. Commitment # 3 in Attachment C to the May 26, 2004 application states: "If an EDG is unavailable, an EDG on the opposite unit will be removed from service only for corrective maintenance ...." Under the proposed 14-day AOT, it would appear that one EDG from one unit could be out-of-service for PM and one EDG from the other unit could be out-of-service for CM for almost the full 14 days. The risk assessment for this scenario was not included in the submittal. Please provide a risk assessment for the case where one EDG from one unit is in PM and one from the other unit is in CM at the same time or provide justification to prevent such an occurrence. (RG 1.174, Section 2.2.2; RG 1.177 Section 2.3)

   Response:

   The current On-Line Work Management and Risk Assessment procedure (1/2-ADM-0804) states that:

   > Only one of the four emergency diesel generators at both Unit 1 and Unit 2 will be intentionally removed from service at the same time. This is not applicable when <u>BOTH</u> Unit 1 and Unit 2 are in shutdown modes. The performance of Diesel Surveillance Testing is exempted from this requirement.

   Therefore, it is not expected that a condition would arise where one EDG from one unit is in preventative maintenance and one from the other unit is in corrective maintenance at the same time, especially for the full 14-days. However, if this condition did exist the conscientious site practice would be to work the EDG that is in corrective maintenance around the clock until it is repaired. If the repair time was estimated to take longer than the time to restore the EDG that is in preventative maintenance, then the focus would be to work around the clock to restore the EDG in PM.

   Although, this alignment would not be intentionally scheduled, the on-line risk configuration program (Safety Monitor) evaluated the risk associated with taking one EDG out-of-service at each unit concurrently, and assuming that all other equipment was available. The risk increase associated with this alignment remained within the GREEN threshold values (i.e., less than two times the no maintenance CDF) at both units.

10. The LAR says that Table 5 was developed using Cases 3, 4, 5 and 6. If Case 5 is compared to Case 1, the incremental conditional core damage probability (ICCDP) over 12 hours would appear to be 4.3E-7 (BVPS-1) and 2.7E-6 (BVPS-2) compared to 4.75E-8 and 4.93E-7, respectively, shown in Table 5. Please explain how Table 5 was developed. (RG 1.174, Section 2.2.2; RG 1.177 Section 2.3)

    Response:

    LAR Table 5 provided the evaluation of the ICCDP and ICLERP results, while an EDG is unavailable for corrective maintenance during the extended AOT. The evaluation was developed based on various corrective maintenance configurations, while crediting the restrictions in Technical Specification 3.8.1.1 action statements b and c for maximum allowable time for demonstrating absence of common cause failures and allowable time limit of 12 hours for a condition in which both the offsite power source and an EDG are inoperable. These configurations model Technical Specification 3.8.1.1 actions b and c, and account for the fraction of time that each condition is expected. Strictly calculating the ICCDP using Case 5 and comparing it to Case 1 does not account for the fraction of the year that the offsite power circuit fails. That is to say, that it will assume that every time the EDG is unavailable, an offsite power circuit is also unavailable. Because the LAR submittal is strictly for an EDG AOT extension, the increase in conditional probabilities should be solely based on the guaranteed failure of a single EDG, and not the guaranteed failure of both an EDG and one offsite power circuit.

- Tech Spec 3.8.1.1 Action b (one EDG inoperable with offsite power circuits operable)

  T = 0 One EDG becomes inoperable (Case 4)

  T = 1 hr Other sources are verified operable by SR 4.8.1.1.1.a verifying breakers (No impact)

  T = 24 hr Common Cause failure potential is eliminated from other EDG based on SR 4.8.1.1.2.a.5 (Same risk impact as Case 3, since one EDG is inoperable and common cause failures on the other EDG eliminated)

  T = AOT duration EDG is restored operable

- Tech Spec 3.8.1.1 Action c (one EDG and one offsite circuit inoperable)

  T = 0 One EDG becomes inoperable and 1 offsite power circuit becomes inoperable (Case 5)

  T = 1 hr Other sources are verified operable by SR 4.8.1.1.1.a verifying breakers (No impact)

  T = 8 hr Common Cause failure potential is eliminated from other EDG based on SR 4.8.1.1.2.a.5 (Case 6)

  T = 12 hr Restore offsite power circuit (Same risk impact as Case 3)

  T = AOT duration EDG is restored operable.

The total conditional core damage probability then is the CCDP while in action b times the probability that the offsite power circuits are available (i.e., 1- split faction NA1) plus the CCDP while in action c times the probability that an offsite power circuit is unavailable (i.e., split faction NA1). For Unit 1 the split faction value for NA1= 3.51E-03 and Unit 2's NA1= 4.72E-03.

$$CCDP_{AOT} = ((\text{Case } 4 * 24 \text{ hr}) + (\text{Case } 3 * (\text{AOT duration} - 24 \text{ hr})))/8760 * (1\text{-NA1})$$
$$+ ((\text{Case } 5 * 8 \text{ hr}) + (\text{Case } 6 * 4 \text{ hr}) + (\text{Case } 3 * (\text{AOT duration} - 12 \text{ hr})))/8760 * \text{NA1}$$

For Unit 1:

$CCDP_{AOT}$ = ((2.63E-05 * 24) + (2.45E-05 * 312)) / 8760 * (1- 3.51E-03) + ((3.37E-04 * 8) + (3.24E-04 * 4) + (2.45E-05 * 324)) / 8760 * 3.51E-03

$CCDP_{AOT}$ = 9.45E-07

The base core damage probability is the base case CDF times the AOT duration.

CDP_{base} = (Case 1 * AOT duration)/8760

CDP_{base} = (2.34E-05 * 336) / 8760

CDP_{base} = 8.98E-07

$ICCDP = CCDP_{AOT} - CDP_{base}$

ICCDP = 4.75E-08

For Unit 2:

$CCDP_{AOT}$ = ((7.60E-05 * 24) + (4.29E-05 * 312)) / 8760 * (1- 4.72E-03) + ((2.01E-03 * 8) + (1.67E-03 * 4) + (4.29E-05 * 324)) / 8760 * 4.72E-03

$CCDP_{AOT}$ = 1.75E-06

The base core damage probability is the base case CDF times the AOT duration.

CDP_{base} = (Case 1 * AOT duration)/8760

CDP_{base} = (3.27E-05 * 336) / 8760

CDP_{base} = 1.26E-06

$ICCDP = CCDP_{AOT} - CDP_{base}$

ICCDP = 4.93E-07

Similarly the conditional large early release probability (CLERP) is derived using the same approach. It should be noted that at Unit 2, since there is a reduction in LERF associated with one EDG being unavailable (LAR Table 1 Case 3 compared to Case 1) the incremental CLERP is risk neutral.

11. Please explain the following with respect to the risk assessment: (RG 1.174, Section 2.2.2; RG 1.177 Section 2.3)

    a. Why is BVPS-2 core damage frequency (CDF) so much more sensitive to EDG dependability than BVPS-1? Example 1: Table 2 shows delta CDF for BVPS-2 is 1.24 E-6 greater than BVPS-1 delta CDF, even though the increase in EDG unavailability is smaller for BVPS-2. Example 2: Table 1 indicates a greater percent increase in BVPS-2 CDF than BVPS-1 for Cases 2 through 6.

       Response:

       At Unit 1, almost half of the core damage frequency is associated with seismic events, which are largely unaffected by EDG unavailability. This is either due to direct seismic failures of the emergency AC busses, or indirect seismic failures of the EDG support systems. Examples of support system failures include the seismic failure of offsite power coincident with the seismic failure of 125V DC power or the river/service water system, either directly or through the collapse of the Auxiliary Building housing river/service piping. These seismic failures result in the guaranteed failure of the emergency AC busses and are assumed to be non-recoverable. Therefore, the unavailability of an EDG does not contribute to approximately 50% of the Unit 1 CDF.

       Additionally, another 11% of the CDF is attributed to the failure of the emergency switchgear ventilation following a fire in the cable spreading room, CS-1 (see description for Unit 1, Case 2, Sequence 1 in response to RAI question 8). These sequences also remain essentially unaffected by the increased EDG AOT, since the PRA model assumes that all AC power is failed and non-recoverable due to the loss of emergency switchgear ventilation. Therefore, only about 39% of the CDF at Unit 1 can be impacted by EDG unavailability.

       At Unit 2, only about 30% of the core damage frequency is associated with seismic events, so there are not as many guaranteed failures of the emergency AC busses. Therefore, the probabilistic failure of an EDG, which increases with AOT unavailability, can impact more core damage sequences. Consequently, almost 70% of the Unit 2 CDF can be impacted by EDG unavailability. As a result of these differences, the CDF at Unit 2 is much more sensitive to EDG unavailability than Unit 1.

    b. Why is BVPS-2 large early release frequency (LERF) less sensitive to EDG dependability than BVPS-1? Example: The percent increase in LERF for Cases 5 and 6 is much smaller for BVPS-2 than for BVPS-1?

       Response:

       At Unit 1, the PRA model assumes that interfacing systems LOCA events can be mitigated, given that a HHSI pump can provide continued RCS inventory makeup via the RWST. These interfacing systems LOCAs dominate the LERF at Unit 1 for Cases 5 and

6 (greater than 98% contribution to LERF) due to the probability of failing to makeup to the RWST, given that one offsite circuit and emergency AC orange power has failed. Without continued RCS makeup, the interfacing systems LOCA can not be mitigated and the conditional LERP increases from about 7E-03 to essentially 1.0, resulting in an increase in the LERF by about 1.0E-05.

At Unit 2, the PRA models did not credit any mitigating actions to reduce the interfacing systems LOCA since the initiating event frequency was almost 2 orders of magnitude lower than Unit 1's (1.07E-05 at Unit 1 vs. 2.80E-07 at Unit 2), due to system arrangements. As a result, the interfacing systems LOCA conditional LERP remains constant at 1.0, and the LERF contribution remains essentially the same as the initiating event frequency for all Cases analyzed.

Therefore, the impact to LERF at Unit 1 is much more sensitive to the EDG dependency than Unit 2, due to the interfacing systems LOCA conditional LERP.

c. Why is BVPS-2 LERF for Cases 3 and 4 less than Case 1, even though the respective CDF values are greater than Case 1?

Response:

A large portion of the LERF at Unit 2 is attributed to Steam Generator Tube Rupture (SGTR) events with failure of the steam lines to isolate (top event SL) and failure to makeup to the RWST (top event WM). The supporting AC power systems for top event WM are the normal 4KV busses. In the Case 3 and 4 analyses, it is known that only the EDG is unavailable and the offsite circuit supplies to the EDGs are available (unavailability of an offsite circuit supply to an EDG is analyzed in Cases 5 and 6). Given this knowledge, the failure probability of the normal 4KV busses is lower in Cases 3 and 4, than was analyzed in Case 1, where there was some maintenance unavailability associated with the busses. The impact of the reduction in the normal 4KV bus failure probability can be seen in Table 13, with the following LERF sequences for Case 1 and 3 (with Case 4 similar to Case 3).

Table 13 Unit 2 SGTR LERF Sequences		
Case 1		
Initiator	**Frequency**	**Failed and Multi-State Split Fractions**
SGTRA	1.5903E-08	ZXF*NA1*ND3*SL1A*WMF*NRF*NMF*REF*SSF*CG1
SGTRB	1.5903E-08	ZXF*NA1*ND3*SL1B*WMF*NRF*NMF*REF*SSF*CG1
SGTRC	1.5903E-08	ZXF*NA1*ND3*SL1C*WMF*NRF*NMF*REF*SSF*CG1
	4.7709E-08	
Case 3		
Initiator	**Frequency**	**Failed and Multi-State Split Fractions**
SGTRA	4.7214E-10	ZXF*NA1*ND3*AO2*M1F*M3F*WAF*SL2A*WMF*NRF*NMF*R1F*RCF*RE5A*SSF*CG1
SGTRB	3.9683E-10	ZXF*NA1*ND3*AO2*M1F*M3F*WAF*SL2B*WMF*NRF*NMF*R1F*RCF*RE5A*SSF*CG1
SGTRC	3.9698E-10	ZXF*NA1*ND3*AO2*M1F*M3F*WAF*SL2C*WMF*NRF*NMF*R1F*RCF*RE5A*SSF*CG1
	1.2660E-09	

As can be seen in Case 1, the failure of both of the normal 4KV busses 2A (split fraction NA1) and 2D (split fraction ND3) lead to the guaranteed failure of RWST makeup (Split fraction WMF). Since the EDGs are successful in powering the emergency AC busses, as shown by the lack of any AO or BP split fractions, electric power recovery by replacing fast bus transfer breakers is not credited (split fraction REF). With the emergency AC busses available, 125V DC power to the turbine driven auxiliary feedwater (TDAFW) pump steam supply valves remains available to keep the valves closed (valves fail open on loss of DC power), and operator actions to close the valves can be performed in the control room. However, these actions fail as shown by the presence of split fractions SL1A, SL1B, or SL1C, which indicates steam line isolation failure. The cumulative LERF for just these three sequences is 4.7709E-08.

The exact SGTR sequences described in Case 1 are not present in Case 3, due the guaranteed failure of the train A emergency AC bus as a result of the EDG being out-of-service and failure of the supporting normal 4KV bus. Therefore, these sequences are eliminated from the CDF/LERF contribution in Case 3, and would instead progress to the three sequences identified in the above Table 13 Case 3.

For Case 3, the failure of both of the normal 4KV busses 2A and 2D also lead to the guaranteed failure of RWST makeup. But as discussed above, these have lower failure probabilities than the NA1 and ND3 split fractions for Case 1. Also, since the train A EDG is assumed to be unavailable, the train A emergency AC bus is now a guaranteed failure (split fraction AO2 = 1.0), and credit for electric power recovery by replacing the fast bus transfer breakers is credited to re-power the train A emergency AC bus. However, this action fails as shown by the presence of split fraction RE5A. With the train A emergency AC bus unavailable, it is assumed that 125V DC power to the A steam generator's TDAFW pump steam supply valves is eventually lost and the valves fail open. This requires operator actions to locally close the manual isolation valves and terminate any RCS leakage out the steam lines. However, as shown by the presence of split fractions SL2A, SL2B, or SL2C, these operator actions also fail. It should be noted that only the A steam generator's TDAFW pump steam supply valves are impacted by the failure of the train A emergency AC bus. Therefore, the local operator actions to isolate these valves are only required during a SGTR on the A steam generator (initiator SGTRA), and hence this sequence has a higher frequency than the SGTRB or SGTRC initiators. The cumulative LERF for just these three Case 3 sequences is 1.2660E-09. These same three sequences would also be present in Case 1, but of a lower frequency since the train A emergency AC bus would be a probabilistic failure and not a guaranteed failure. The cumulative LERF for these same three sequences that would be present in Case 1 is 4.5901E-10.

When taking the difference in just these three LERF sequences in Table 13, it can be seen that there is a reduction of almost 5E-08 in the Case 3 LERF. Since CDF sequences have a lot more initiating events contributing to the frequency than just SGTRs, there is an overall increase in CDF for Cases 3 and 4 when compared to Case 1.

d. Why is Unit 1 Case 6 LERF higher than Case 5 LERF, when the corresponding CDF is lower?

Response:

The slight difference in the LERF values between Unit 1 Case 5 and Case 6 can be attributed to the truncation frequency of the sequences quantified (1.0E-12) and the contribution of train B emergency AC power success terms. Since Case 5 includes common cause failures of the available EDG, the train B emergency AC power conditional failure probability, whenever the associated normal 4KV bus is failed, is higher in Case 5 than it is Case 6. Therefore, the retained LERF sequences with success terms for the train B emergency AC power (1- failure probability) are lower in Case 5 than they are in Case 6.

Round off of these retained LERF sequences to two decimal places in LAR Table 1 accounts for the increase of 1.0E-07 in Case 6 over Case 5. However, the actual increase in the retained LERF sequences for Case 6 is only 3.4E-09, when compared to Case 5. Since the CDF is based on a larger set of initiators, this success term impact is not as influential in the Unit 1 Case 6 CDF.

e. In Tier 1 of the LAR, the BVPS-2 EDG unavailability is estimated to increase to 156.8 hours per year per EDG. Table 3 shows a total of 389.7 hours per year EDG unavailability, which corresponds to 194.85 hours per year per EDG. Please explain this difference in estimated unavailability.

Response:

In the Unit 2 Tier 1 analysis, the extended EDG AOT unavailability was estimated based upon the expected mean time for tests (10.5 hours) and for maintenance (146.21 hours), for a total unavailability time of about 156.8 hours per EDG . The 146.21 hours of expected mean time for maintenance was based on 43.17 hours of corrective maintenance, and 103.02 hours of preventative maintenance. See Tables 1 and 2 in the response to RAI question 6 for more details on this unavailability. This Unit 2 EDG unavailability time (or 1.79%) was then used to calculate the CDF values shown in LAR Table 1 Case 2. The change in CDF given in Table 2 was derived by using this CDF and subtracting off the Case 1 baseline value CDF. However, when using this approach, it does not discount for maintenance alignments that would not be allowed, either by Technical Specifications or by the On-Line Maintenance procedure (e.g., one EDG unavailable with one offsite power circuit out-of-service). Nor does this approach eliminate the effects of common cause failures, when corrective maintenance would put the plant into these restricted alignments.

In order to account for these restricted maintenance alignments, LAR Table 3 was generated. The 389.7 hours of Unit 2 EDG unavailability presented in Table 3 also assumes that there are 10.5 hours associated with tests (surveillances) and about 43.2 hours associated with corrective maintenance. However, the EDG unavailability time associated with preventative maintenance was increased to the full 14-day AOT (336 hours) for conservatism. Therefore, the total EDG unavailability assumed in the Table 3 CCDP analysis was 389.7 hours per EDG. This value was then used to derive the Delta CDF presented on page 19 of the LAR submittal.

Upon further review of the LAR Table 3 CCDP value during the response to this RAI question, it was noted that the Delta CDF calculation only accounts for one EDG being unavailable throughout the year. Therefore, the following replacement Table 3 and Delta CDF calculation are presented to account for two EDGs being unavailable during the year. This revised table also assumes that the expected preventative maintenance unavailability for Case 3 is 103.02 hours per EDG. This corresponds to the Unit 2 Tier 1 analysis assumed EDG hours, instead of the conservative full 14-day AOT (336 hours) used in LAR Table 3.

Revised Table 3
BVPS-2 Conditional CDP
Using Expected Time in Maintenance Alignments

Case	Alignment Description	Conditional CDF (per yr)	Hrs	CCDP
Corrective Maint. (Case 4)	One EDG in Corrective Maintenance	7.60E-05	86.4	7.50E-07
Preventive Maint. (Case 3)	One EDG in Preventive Maintenance	4.29E-05	206.0	1.01E-06
Surveillances (Case 4)	One EDG in routine surveillance testing	7.60E-05	21.0	1.82E-07
Baseline (Case 1)	Base case assumptions for remainder of year	3.27E-05	8446.6	3.15E-05
			CCDP Summation	3.35E-05

The revised increase in the BVPS Unit 2 CDF based on the expected time in the preventive and corrective alignments is therefore:

Revised Delta CDF = (CDF expected time in maint. alignments) - (CDF for Baseline)

= (3.35E-05) - (3.27E-05)

= 7.71E-07 per reactor year

As can be seen in the revised Delta CDF results, the calculated increase in CDF for BVPS Unit 2 using the expected time in the preventive and corrective maintenance alignments is still less than the Regulatory Guide 1.174 acceptance guideline of 1E-6 per reactor year for demonstrating a very small increase in plant risk.

f. In Table 4 of the LAR, please explain why BVPS-2 incremental conditional large early release probability (ICLERP) is "risk neutral" with an EDG out of service, but BVPS-1 demonstrates an increase under the same conditions?

Response:

ICLERP was derived by subtracting the Case 1 LERF from the Case 3 LERF, then multiplying the result by expected duration or full 14-day AOT duration divided by the number of hours in a year. Since the LERF value at Unit 2 for Case 3 (see response to RAI question 11.c) is less than it is for Case 1, there is a reduction in the ICLERP value, or "risk neutral" result. This is not the case for Unit 1, where the Case 3 LERF is slightly higher than the Case 1 LERF.

12. Discuss and provide information on the reliability and availability of offsite power sources relating to the proposed change. Provide the basis the loss of offsite power (LOOP) frequencies and non-recovery probabilities used in the PRA models. Were they adjusted as a result of the New York area blackout of August, 2003? If not, why not? How is the potential for loss of offsite power given a non-LOOP initiating event (e.g., "consequential LOOP") modeled in the BVPS-1 and 2 PRA models? (RG 1.174, Section 2.2.2; RG 1.177 Section 2.3)

Response:

The offsite power sources for both BVPS Unit 1 and Unit 2 consist of two physically independent circuits between the offsite transmission network and the onsite power systems. Each offsite circuit consists of a 138 KV switchyard bus connected to a system station service transformer (SSST) which can provide power to two of the four normal 4 KV station buses. One of these two normal 4KV buses supplies power to one of the redundant 4KV emergency buses through two series tie breakers to complete the offsite power circuit. During normal power operation, the normal 4 KV station buses are supplied from the station output through the unit station service transformers (USST). Following a unit trip, the normal 4KV buses are transferred to the offsite power sources by a fast bus transfer scheme which transfers the normal 4 KV buses power source to the SSSTs.

In the event that one of the required offsite power circuits becomes inoperable, the BVPS Unit 1 and Unit 2 Technical Specifications (TS 3.8.1.1) requires the inoperable offsite power circuit be returned to operable status within 72 hours, or a plant shutdown be initiated.

If both one of the required offsite power circuits and an EDG are inoperable, the BVPS Unit 1 and Unit 2 TS 3.8.1.1 requires one of the inoperable power sources be returned to operable status within 12 hours, or a plant shutdown initiated.

The following Tier 2 restrictions will be required when removing an EDG from service for scheduled maintenance, as provided in the LAR 1A-306 & 2A-176, to ensure availability of the offsite power circuits.

- If either offsite power circuit is unavailable, an EDG will be removed from service only for corrective maintenance, i.e., maintenance required to restore operability.
- If an EDG is unavailable, the offsite power circuits will be removed from service only for corrective maintenance required to restore operability.
- An EDG will not be removed from service for scheduled maintenance if weather forecasts are predicting severe weather conditions for the BVPS area with the potential to degrade or limit offsite power availability.
- When an EDG is removed from service for scheduled maintenance, no discretionary switchyard maintenance will be allowed. In addition, switchyard access will be strictly controlled by the control room operating crew to minimize the potential for offsite power transients.
- Prior to removing the EDG from service, the stability of the offsite power system in the vicinity of BVPS will be verified by contacting the FirstEnergy and Duquesne Light

Company System Control Centers to determine the projected load demand and status of the grid during the period the EDG will be unavailable.

The following discussion provides information related to station loss of offsite power events.

The BVPS operating history was reviewed for station events related to loss of offsite power sources. This review covered the period of 1985 to present (20 years) for Unit 1 and from initial operation (1987) to present for Unit 2.

During this period the station experienced two total loss of offsite power events as discussed below:

10/12/93 BVPS Unit 1 and Unit 2 experienced a loss of all offsite power sources when various offsite feeder breakers in the switchyard opened unexpectedly. Prior to the event Unit 1 was operating a full power and Unit 2 was in a refueling outage. The operation of the switchyard breakers caused a loss of the majority of the Unit 1 electrical load and subsequent turbine/reactor trip. The event was caused by personnel error while performing maintenance on the Unit 2 main output breaker. Offsite power was restored in approximately 10 minutes at Unit 1 and 15 minutes at Unit 2. (LER 334/93-13)

11/17/87 BVPS Unit 2 experienced a loss of all offsite power sources following a Turbine/Reactor Trip from full power. The Unit 2 138 KV offsite power supply breakers opened during the transfer to offsite power following the unit trip. The event was caused by a problem with the normal supply breaker control scheme which allowed these breakers to reclose momentarily during the transfer to offsite power. One of the offsite power sources was lost only momentarily during the event. The other offsite power source was restored in approximately 8 hours. (LER 412/87-36)

Twelve events were identified during the review period that involved a partial loss (loss of one offsite power source to the station emergency buses). Seven of these events occurred at Unit 2 during the first few years of operation (1987 – 1990). Since then five events have occurred and are discussed below:

2/27/03 (Unit 1) One of the two 4KV emergency buses was isolated from its offsite power source when the offsite supply breaker to the normal 4KV bus supplying the emergency bus tripped open. The cause of the event was improper installation of an electrical protection relay which actuated when starting a main feedwater pump. (LER 334/03-03)

10/12/99 (Unit 2) The station automatic bus transfer capability to one of the offsite power sources was unavailable for approximately 5 hours due to personnel error. Manual transfer capability was available. (LER 412/99-09)

7/16/99	(Unit 2) One of the two 4KV emergency buses was isolated from its offsite power source when the emergency bus supply breaker from the normal 4KV bus supplying the emergency bus tripped open. The cause of the event was an erratic EDG voltage regulator which actuated a protective relay operation. (LER 412/99-06)
3/29/99	(Unit 2) One of the two 4KV emergency buses was isolated from its offsite power source when the normal 4KV bus supply to the emergency bus was de-energized due to an inadvertent protective relay actuation which locked-out the offsite supply to the normal 4KV bus. The protective relay actuation was caused by relay control power fluctuations. (LER 412/99-05)
6/1/94	(Unit 2) The 2A Station System Service Transformer offsite power source was de-energized due to an inadvertent protective relay actuation associated with the 138 KV buses. The event was caused by a system electrical disturbance following a Unit 1 plant trip. (LER 334/94-05)

The basis for the PRA model loss of offsite power (LOSP) frequencies comes from reviewing industry data presented in the following sources:

NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," November 1998

NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995," February 1999, and

EPRI Technical Report 1000158, "Losses of Off-Site Power at U.S. Nuclear Power Plants – Through 1999," July 2000.

Because the EPRI study thoroughly reviewed LOSP events, it was considered to be a better source of data for LOSP events than NUREG/CR-5750 and had more recent data than NUREG/CR-5496. Therefore, the EPRI report was used to develop the first stage (prior/generic) LOSP distribution using a two-stage Bayesian methodology with the following attributes:

Mean = 2.74E-02
5th Percentile = 4.93E-03
Median = 2.20E-02
95th Percentile = 6.34E-02

The BVPS plant specific LOSP event count and critical years of operation were then used to update the prior distribution in the second-stage of the Bayesian update to derive a LOSP distribution for the BVPS plant specific initiating event.

In order for an event to be classified as an LOSP, the PRA model assumes that both the outgoing 345KV and incoming 138KV lines must be lost. If only the 138KV lines are lost, the unit does not trip since the unit station service transformers (USST) are supplying normal 4KV power. Consequently, loss of only the 138KV lines is not modeled as an initiating event in the PRA models. If the 345KV line is lost it results in a generator trip, but equipment is re-powered when the fast bus transfer to the 138KV line is completed. This loss of load event is captured in the turbine trip (TTRIP) PRA model initiating event frequency. Additionally, if only one normal 4KV bus is lost, it is captured in the loss of a 4160V bus (LB1A, LB1D, LB2A, or LB2D) PRA model initiating event frequency. It should also be mentioned that in response to PRA Peer Review F&O IE-04, derivations of initiating event frequencies did not use data from the initial year of commercial operation, since the use of this data, though conservative, could shift the importance of components, which could affect future use of the PRA for risk-informed applications.

For Unit 1:

The LOSP initiating event frequency developed for the baseline Unit 1 PRA model captured initiating events starting on January 1, 1980 and ending on December 31, 2001. Using the initiating event definitions defined above, only 1 event was retained in the LOSP category during the 15.8 years of critical power operation. Using a two-stage Bayesian update approach with this information and the LOSP prior distribution, a posterior value of 3.16E-02 is obtained.

For Unit 2:

The LOSP initiating event frequency developed for the baseline Unit 2 PRA model captured initiating events starting on January 1, 1989 and ending on May 31, 2001. Using the initiating event definitions defined above, no events were retained in the LOSP category during the 9.93 years of critical power operation, when excluding the use data from the initial year of commercial operation and plant shutdown conditions. Using a two-stage Bayesian update approach with this information and the LOSP prior distribution, a posterior value of 2.31E-02 is obtained.

In the BVPS PRA models, two offsite power non-recovery probability distributions were developed; one for times to core uncovery prior to 20 hours used in the electric power recovery STADIC code, and one for times to core uncovery greater than 20 hours. This methodology was chosen over strictly using the STADIC electric power recovery model for all times, since the offsite power recovery curves used in STADIC model are constant between 12 and 100 hours, and would not provide for any additional credit for offsite power recovery after 12 hours.

The mean probability of non-recovery of offsite power used in the STADIC code for the BVPS IPE electric power recovery models were developed from data presented in NSAC-144, "Losses of Offsite Power at U.S. Nuclear Power Plants All Years Through 1988," April 1989. In addition, specific line item data from the Seabrook site and South Texas Project site were used with data from NUREG/CR-5032 to develop the distributions from the mean for the 10th and 90th percentile cases. Together, these distributions form the basis for the offsite power non-recovery probability, used in the BVPS PRA electric power recovery models for times to core uncovery prior to 20 hours, and are shown at the end of this response.

As part of the PRA model update process, a review of more recent work on LOSP events at nuclear power plants, as documented in NUREG/CR-5496, indicates that the recovery curves for offsite power recovery time in the NUREG report (for example, Figure 3-4 of NUREG/CR-5496) matches quite closely to the 10^{th} percentile recovery curve used in the BVPS IPE analyses. The recovery curves used in the BVPS IPE electric power recovery analyses are, therefore, slightly more conservative compared to the one documented in the NUREG/CR-5496 report. Consequently, the offsite power recovery curves developed for the BVPS IPEs were still utilized in the updated PRA electric power recovery models.

For times to core uncovery greater than 20 hours, the probability of not recovering offsite power before core uncovery occurs was developed using the Plant-Centered LOOP Recovery lognormal distribution (median = 29.6 min, error factor = 10.6) reported in NUREG/CR-5496. The plant-centered LOOP recovery values were chosen over the weather related LOOP values, since electric power recovery is not credited for external initiating events in the BVPS PRA models. The complementary cumulative distribution of the plant-centered LOOP recovery represents the probability that offsite power is not recovered, and is shown in Figure 3-4 of NUREG/CR-5496. This figure formed the basis for the electric power non-recovery factors for core uncovery times greater than 20 hours.

If core damage does not occur within 48 hours following the loss of seal cooling, the BVPS SBO sensitivity cases using MAAP show that RCS conditions (temperature, pressure, and level) are controlled and safety injection recirculation is not required. Therefore, electric power recovery of some type is assumed to be a guaranteed success for these sequences, and they are not binned to a core damage end state in the PRA models. The underlying assumption in this approach is that there would be sufficient time to implement recovery strategies from the Beaver Valley Severe Accident Management Guidelines (SAMGs) prior to the onset of core damage.

The New York Area blackout of August 2003 did not adversely impact either of the BVPS Units enough to result in a plant trip or loss of offsite power. Therefore, data obtained from this event was not used to update the LOSP initiating event frequency when performing the EDG AOT extension evaluations.

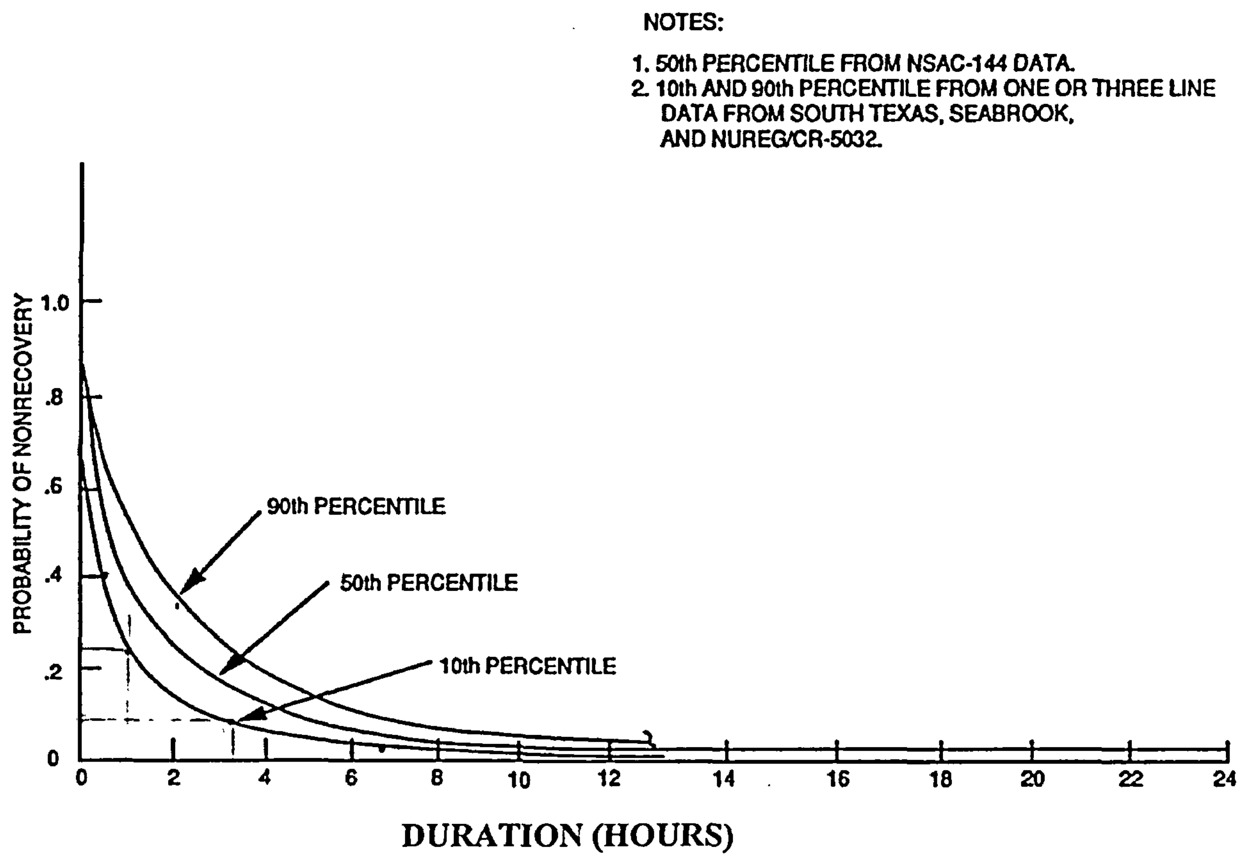
However in response to this RAI question, a sensitivity was performed on the LOSP IE frequency assuming that each of the Units observed one additional LOSP event through the end of 2003 by using the two-stage Bayesian update approach. As previously mentioned, the current PRA models used December 2001 and May 2001 as the initiating event data cutoff dates for the Unit 1 and Unit 2 PRA model updates, respectively. Therefore, at Unit 1 the two-stage Bayesian update of the LOSP frequency used 2 events during 17.8 years of critical power operation, while Unit 2 used 1 event in 12.5 years of critical power operation. The results of this LOSP sensitivity and the impact on the CDF (by using Tables 5, 7, 9, and 11 to calculate conditional core damage probabilities) are given in the table below.

New York Area Blackout of August 2003 CDF Impact Sensitivity						
	LAR LOSP IE Frequency	LAR LOSP CDF*	CCDP	RAI LOSP IE Frequency	RAI LOSP CDF	Delta CDF
Unit 1						
Case 1	3.16E-02	2.87E-07	9.09E-06	4.45E-02	4.05E-07	1.17E-07
Case 2	3.16E-02	3.14E-07	9.95E-06	4.45E-02	4.43E-07	1.28E-07
Unit 2						
Case 1	2.31E-02	4.02E-07	1.74E-05	3.35E-02	5.83E-07	1.81E-07
Case 2	2.31E-02	4.47E-07	1.94E-05	3.35E-02	6.48E-07	2.01E-07
* These values are obtained from Tables 5, 7, 9, and 11 of this RAI.						

Consequential LOOP events are evaluated in top event OG in the PRA models. This top event models the supply of AC power from the 138KV switchyard to the SSSTs following a plant trip and is based on data from PLG-0500 Revision 1, 1989. For the loss of offsite power initiating event, this top event is assumed to be guaranteed failed. Loss of power at the 138KV grid will result in failure of the normal power supply to all of the emergency and non-emergency AC buses.

Following a plant initiating event, the turbine generator is assumed to trip, thereby requiring a fast bus transfer of the non-emergency normal 4KV buses from the USSTs to the SSSTs. Power for these fast bus transfer breakers are modeled in the normal DC power top events, while the breakers, normal 4KV busses, and SSSTs are modeled in the normal 4KV power top events. If top event OG fails, the normal 4KV power top events are assumed to be guaranteed failed, thereby requiring the EDGs to start and load.

OFFSITE POWER NON-RECOVERY DISTRIBUTIONS



13. The LAR proposes to change footnote (1) of Technical Specification (TS) 3.8.1.1 as follows: "Required actions may be delayed for up to 7 days if the diesel generator(s) is inoperable solely due to the fuel oil contained in the storage tanks not meeting the properties in accordance with [TSs] 4.8.1.1.2.d.2 or 4.8.1.1.2.e." This proposed change appears to have two impacts: (1) Extends from 24 hours to 7 days the actions to verify operability of the other diesel or determine that no common mode failure is present; and (2) The time to return the fuel oil to within specifications is not longer explicitly stated and could be interpreted as up to 21 days (i.e., 7 + 14).

    Please clarify the intent of the proposed change to this footnote. What experience has the site had with fuel oil not meeting the surveillance requirements in TS 4.8.1.1.2.d.2 or TS 4.8.1.1.2.e? Is there an increasing trend in failure to meet these specifications? (RG 1.174, Section 2.2.2; RG 1.177 Section 2.3)

Response:

The changes to footnote (1) were proposed to provide clarification to the existing wording of the footnote which does not clearly define application of the associated action statements when an EDG is inoperable due to failure to meet the fuel oil property limits of surveillance requirements 4.8.1.1.2.d.2 or 4.8.1.1.2.e. With the current wording of this footnote and the proposed change to the EDG AOT, it could be interpreted that a more restrictive 7 days is allowed to restore EDG fuel oil to within limits than the proposed 14 days for restoring an inoperable EDG to operability. The Standard Technical Specifications for Westinghouse Plants, NUREG 1431, Specification 3.8.3 for Diesel Fuel Oil, Lube Oil and Starting Air, allows 7 days for restoring EDG fuel oil particulate to within limits (and up to 30 days for restoring new fuel oil properties to within limits) prior to declaring the EDGs inoperable and entering the required actions of Specification 3.8.1. Since the BVPS Technical Specifications provide EDG fuel oil surveillance requirements within the same LCO for the EDG, failure to meet these surveillance requirements requires the affect EDG to be declared inoperable. The proposed changes to footnote (1) would allow the action requirements for an EDG declared inoperable due to failure to meet the above fuel oil surveillance requirements to be delayed similar to the provisions in NUREG 1431. With the proposed change to the footnote, 7 days would be allowed to restore the fuel oil to within limits prior to entering the applicable action statement after which the 14 day AOT would apply to the affected EDG and the associated action requirements, including operability of the other diesel or determining that no common cause is present.

The past five years of EDG fuel oil sampling data required by surveillance requirements 4.8.1.1.2.d.2 and 4.8.1.1.2.e for BVPS Units 1 and 2 were reviewed by the BVPS Chemistry Department. None of the samples for these surveillance requirements showed any increasing trends either in failure to meet the surveillance requirement specifications or towards failure to meet the surveillance requirement specifications. In the five year period reviewed, there was only one result that failed to meet the specifications of the two surveillance requirements: the Unit 2 carbon residue on 10% bottoms on a new fuel oil delivery to EDG fuel oil storage tank 2EGF-TK21B of 3/19/04. The carbon residue result was 0.37%, which failed to meet the carbon residue specification of less than or equal to 0.35%. This was documented in CR 04-03416. Follow-up samples of the 2EGF-TK21B storage tank showed that the tank's carbon residue value had remained within specification at 0.15%. A review of all carbon residue on 10% bottoms new fuel oil results showed the 3/19/04 results to be an isolated case.

ATTACHMENT B

Letter L-04-141

KEY DIFFERENCES IN THE BVPS PRA MODELS AND THEIR IMPACT ON THE EDG AOT EXTENSION

Safety Injection Recirculation Mode

Unit 1: Low Head Safety Injection (LHSI) pumps take suction from the containment sump and discharge to the Reactor Coolant System (RCS) LHSI piping or to the High Head Safety Injection (HHSI) pumps suction.

Unit 2: Recirculation Spray pumps C & D take suction from the containment sump and discharge to the RCS LHSI piping or to the HHSI pumps suction.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension, since all associated pumps receive power from the EDGs.

Service Water / River Water Operating Pumps

Unit 1: Normally one River Water (RW) pump is running with the A & B headers cross-connected. There is also one standby RW pump and one spare RW pump, along with two Auxiliary RW pumps available.

Unit 2: Normally two Service Water (SW) pumps are running, since they support the secondary component cooling water system. There is also one spare SW pump, along with two Standby SW pumps available.

EDG AOT Impact: These differences are only expected to have a slight impact on the risk assessment of the 14-day EDG AOT extension, since the Unit 1 standby RW pump must start to support its EDG, while the Unit 2 pump is already running.

Auxiliary River / Standby Service Pump Starting

Unit 1: The Auxiliary River Water pumps need to be manually started from the control room under all conditions.

Unit 2: The Standby Service Water pumps auto start on low Service Water System pressure, given that offsite power is available. These pumps only need to be manually started from the control room during a loss of offsite power.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension, since all associated pumps must be manually loaded on to the EDG to start, following a loss of offsite power.

Main Feedwater Cooling Water Support Systems

Unit 1: The Raw Water System supplies the secondary cooling water (CCT) loads.

Unit 2: The Service Water System supplies secondary cooling water (CCS) loads.

EDG AOT Impact: These differences are only expected to have a slight impact on the risk assessment of the 14-day EDG AOT extension. The Unit 2 PRA model requires the CCS isolation MOVs to close for a Standby Service Water pump to successfully supply the cooling loads, including the EDGs following a loss of offsite power. This function is not required for the Unit 1 Auxiliary RW pump to cool the EDG, since the Raw Water System supplies the CCT loads.

Emergency Battery Capacity

Unit 1: Battery 1 has 2.4 hours of capacity (used to start EDG #1); Battery 2 has 2.6 hours of capacity (used to start EDG #2); Battery 3 has 3.8 hours of capacity (used for Steam Generator level indication); Battery 4 has 5.6 hours of capacity.

Unit 2: Batteries 1 & 2 have 3.5 hours of capacity (used to start EDGs); Batteries 3 & 4 have 8.0 hours of capacity (used for SG level indication).

EDG AOT Impact: These differences are only expected to have a slight impact on the risk assessment of the 14-day EDG AOT extension. The battery capacities are primarily used in the electric power recovery model (Top Event RE). Batteries 1 and 2 are used to support starting the EDGs. During SBO events, credit is only given for EDG repair/recovery if it can be completed before core uncovery or its support battery depletes, since without the necessary battery capacity the repaired EDG cannot start. The impact between the Unit 1 and Unit 2 batteries 1 & 2 capacities is only slight (less than a 10 percent chance of not recovering a single EDG in 2.4 hrs vs. 3.5 hrs). The difference in the batteries 3 and 4 capacities between the Units is slightly higher. These batteries are used in the electric power recovery model to provide steam generator level indication. Once these batteries deplete, it is assumed in the model that the steam generators will overfill and consequently fail the turbine-driven auxiliary feedwater pump. Without any feedwater, the overfilled steam generator eventually dries-out and core uncovery ensues due to the loss of secondary heat removal. Based on 3.8 hours of capacity at Unit 1, this sequence of events is expected to take about 10 hours to overfill the steam generator and between 14 and 19 hours to uncover the core, depending on Reactor Coolant Pump (RCP) seal leakage. At Unit 2 based on 8 hours of capacity, this same sequence of events is expected to take about 23 hours to overfill the steam generator and between 27 and 37 hours to uncover the core, depending on RCP seal leakage. It should be noted, however, that Unit 1 also credits the dedicated auxiliary feedwater pump to provide water-to-water steam generator cooling in the event of an overfill. Whereas, this alternative is not available at Unit 2.

Emergency Diesel Generator Support Systems

Unit 1: 125V DC Batteries 1 & 2 are required to start the EDG, and Vital Bus I (Red) & II (White) are required to sequence the loads.

Unit 2: Only the 125V DC Batteries 1 & 2 are required to start and load the EDGs.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension. The failure probability of the Unit 1 vital busses is approximately 2.0E-05, which is insignificant when compared to the diesel generator failure probability during a 24-hr mission time (about 4.0E-2).

Dedicated Auxiliary Feedwater Pump

Unit 1: A dedicated auxiliary feedwater (DAFW) pump serves as a backup to the turbine-driven AFW pump during SBO events. The DAFW pump electrical power is backed up by the non-safety related ERF diesel generator and is capable of supplying water to the steam generators for 48 hours. It can also operate in water-to-water heat removal mode if the steam generators are overfilled.

Unit 2: Only the turbine-driven AFW pump can be used during SBO events. This pump is assumed to fail if the steam generators are overfilled, and consequently will lead to core uncovery and damage before a 48-hour mission time.

EDG AOT Impact: These differences have a significant impact on the risk assessment of the 14-day EDG AOT extension. At Unit 1 if DAFW is available and the RCS is cooled down and depressurized, the SBO can be successfully mitigated given that the RCP seal leakage would be less than 182 gpm/RCP at full RCS pressure and temperature conditions. The underlying assumption in this approach is that, since core damage does not occur within 48 hours following the loss of all seal cooling , there would be sufficient time to implement recovery strategies from the Beaver Valley Severe Accident Management Guidelines (SAMGs). Therefore, these sequences are assumed not to result in core damage, since it is expected that some type of electric power recovery can be reestablished with guaranteed success, given 48 hours for implementation. At Unit 2 without a similar pump, all sequences resulted in core damage prior to 48 hours, so all RCP seal LOCAs were binned to a core damage end state.

PPDWST Makeup

Unit 1: Makeup to the Unit 1 Primary Plant Demineralized Water Storage Tank (PPDWST) from the water treatment pumps requires power from normal AC power supplies. There are no makeup capabilities without normal AC power.

Unit 2: Makeup to the Unit 2 PPDWST from water treatment pumps requires power from normal AC power and are backed up by the ERF diesel. There is also a gravity feed flow path available from the Demineralized Water Storage Tank during station blackout conditions to provide additional water to supply the turbine-driven AFW pump.

EDG AOT Impact: These differences are only expected to have an insignificant impact, since the DAFW pump can also be used at Unit 1 during SBO events once the PPDWST depletes. In addition, the diesel-driven fire pump can be aligned to either Unit's TDAFW pump to provide a water supply during SBO events.

RWST Volume

Unit 1: The Refueling Water Storage Tank (RWST) has a water volume of ~ 440,000 gal, makeup is from the spent fuel pool with fire protection system water.

Unit 2: The RWST has a water volume of ~ 860,000 gal, makeup is from the spent fuel pool with Service Water or fire water.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension. The dominant core damage sequences contributing to the increase in risk due to the 14-day EDG AOT extension are some form of an SBO event or failure of one train of AC power and the opposite train of DC power. As such, there are no pumps available to draw suction from the RWST.

Instrument Air

Unit 1: There are two motor-driven station air compressors powered from offsite power and a diesel-driven air compressor. Any one of these compressors can supply all the Unit's compressed air loads including containment instrument air via a normally opened cross-tie to the station instrument air header.

Unit 2: There are two motor-driven station air compressors and two motor-driven containment air compressors located outside containment. The power supplies to all four of these compressors are backed up by the ERF diesel generator. Additionally, a backup air compressor (Condensate Polishing) powered from offsite power is also available. The containment instrument air header can be cross-tied to the station instrument air header, though a normally closed manual valve.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension. Instrument air systems do not contribute significantly to the increase in risk due to the 14-day EDG AOT extension.

Pressurizer PORVs

Unit 1: The Power Operated Relief Valves (PORVs) are air operated relief valves with DC powered solenoid .

Unit 2: The PORVs are DC powered solenoid relief valves.

EDG AOT Impact: These differences are only expected to have an insignificant impact on the risk assessment of the 14-day EDG AOT extension. The failure rates for the PORVs to open and close are similar between the Units (1.1096E-02 and 3.3919E-03 for failure to close and open, respectively at Unit 1; and 1.4185E-02 and 3.6662E-03 for failure to close and open, respectively at Unit 2). Furthermore, the core damage frequency contribution for PORV LOCAs are similar between the Units (5.14E-06/ yr. at Unit 1, and 4.29E-06/ yr. at Unit 2).

Interfacing System's LOCA Initiating Event Frequency

Unit 1: The VSX initiating event frequency at Unit 1 is 1.07E-05 per year. At Unit 1 there is CL-153 piping and associated flanges and seals that would be susceptible to rupturing from exposure to RCS pressure. Such an occurrence would require at least two normally closed valves, which isolate the RCS from low pressure piping, to fail in the open position.

Unit 2: The VSX initiating event frequency at Unit 2 is 2.80E-07 per year. At Unit 2 there is CL-153 piping and associated flanges and seals that would also be susceptible to rupturing from exposure to RCS pressure. However, at Unit 2 such an occurrence would require at least three normally closed valves, which isolate the RCS from low pressure piping, to fail in the open position.

EDG AOT Impact: These differences are only expected to have a significant impact on Unit 1 LERF when an EDG and offsite power circuit is unavailable (see response to RAI question 11.b).

ATTACHMENT C

Letter L-04-141

EMERGENCY DIESEL GENERATOR RECOVERY METHODOLOGY

Diesel Generator Hardware Recovery Model

The most important causes for diesel generator unavailability are diesel generator hardware-related failures during either the startup sequence or the subsequent operation, and diesel generator unavailability due to maintenance at the time of the initiating event. The diesel generator failures include all malfunctions that prevent the unit from delivering stable power to its output bus. These include failures of the engine, generator, mechanical controls, electrical controls, starting systems, and trip systems. The time to return a diesel generator to operation after a hardware failure depends on many factors, such as the cause of failure, repair personnel availability, alternate power supply status, and reactor operating conditions.

The causes of diesel generator hardware failures can range from the spurious operation of a trip solenoid to major physical damage of mechanical or electrical components. Recovery from these failures may involve the simple resetting of a local trip interlock and restarting of the diesel generator, or it may require disassembly and repair of the engine, generator, or its control system. If the time available for electric power recovery is relatively short (for example, less than approximately 2 hours), review of generic diesel generator failure and maintenance data indicates that only the diesel generator startup failures present a significant potential for rapid recovery. Diesel generator failure during operation generally involves more severe problems that require detailed troubleshooting, repairs, or replacement of parts. These are difficult to complete in less than 2 hours.

Finally, because most maintenance events require at least partial reassembly of the diesel generator before it can be started, it is assumed for this analysis that the maintenance contribution to unavailability is also unrecoverable within 2 hours after the initiating event. The following table indicates some of the key actions that can be accomplished within given recovery time periods. This table was developed based on the experience and judgement of the analyst, who was a senior reactor operator. It was not based on plant-specific information, but instead represents assumptions on the time required to perform the actions indicated. These assumptions are believed to be representative of times applicable to Beaver Valley Power Station (and most other plants).

Time Following Operator Response	Action
0 to 5 minutes	Reset trip relay and attempt local manual restart
5 to 15 minutes	Troubleshoot simple problems; check electrical and mechanical indications
15 to 30 minutes	Perform step-by-step problem diagnosis; notify cognizant engineering and maintenance personnel
30 to 60 minutes	Refer to technical manuals and drawings for diagnosis of more complex failures; response time for first offsite personnel
1 to 2 hours	Offsite personnel troubleshoot problems that do not require component repair; make complex adjustments to control systems
2 to 4 hours	Replace simple failed components (includes maintenance crew response time)
4 to 8 hours	Repair failed components requiring minor disassembly
8 to 24 hours	Perform more complex repairs
24 to 72 hours	Make repairs requiring disassembly
< 72 hours	Overhaul diesel engine

It is emphasized that these key actions apply to the recovery for a given failed diesel generator following operator response to that unit and only to the recovery from hardware-related failures. They do not include the time for operators or maintenance personnel to reach the diesel room after the diesel generator fails. It is not the length of time required to recover any one of the failed units. These key actions are used as one piece of information in developing a distribution for the length of time required to recover a failed diesel generator.

The recovery time distribution summarized in the following table applies to situations involving a high urgency for diesel generator repairs. It is not derived directly from actual maintenance event duration data because most diesel generator repairs are not completed under the extremely urgent conditions that prevail after loss of all offsite and onsite AC power. It is based on a review of diesel generator failure and maintenance records collected from several plants, with an assessment of the severity of the observed failures, and the experience of operations and maintenance experts.

Time to Recover a Failed Diesel Generator	
Time Following Operator Response (hours)	**Probability**
0.0 to 0.5	0.20
0.5 to 1.0	0.10
1 to 2	0.15
2 to 4	0.15
4 to 8	0.20
8 to 24	0.10
> 24	0.10

This assumed distribution is used to model the time needed to restore a single diesel generator to operation after the diesel has experienced a hardware failure. It is assumed that repair efforts are continuous from initial troubleshooting until the diesel generator is returned to service. This accounts for factors such as the need to call out additional maintenance personnel for major repairs. Recovery cannot begin until someone goes to the diesel generator room to investigate the failure, and this distribution does not include scenario-specific delays for operating or maintenance personnel reaching the room. These personnel response times are evaluated in the next section and integrated with the hardware repair time distribution to fully model diesel generator recovery for specific failure scenarios.

Diesel Generator Recovery Personnel Response Time Model

Station auxiliary operators are responsible for operating the diesel generators and for initial problem troubleshooting. During the normal work day, additional personnel are also available. An auxiliary operator's normal responsibilities include monitoring plant equipment, changing valve positions and system configurations under direction of the control room operators, and performing walk-through inspections of plant areas. During normal shift working conditions, the operators will usually be moving about various locations or will be at a designated watch area. Other possible, but less likely, locations include the main control room or the administration building.

When offsite power is lost, all diesels will receive signals to start. If diesel generator failures occur after a LOSP, trouble alarms for the diesel generators and other safety systems will be annunciated in the main control room. These alarms, electrical equipment inoperability, and initial verification steps in the plant procedures will provide almost immediate notification to the control room operators, who may attempt to manually restart the affected engine from its control room switch. However, experience has shown that many failures require local troubleshooting to correct the problem and to reset engine trip relays. The control room operators may also be reluctant to quickly restart a diesel generator that tripped during operation before they determine a cause for the failure. For this analysis, it is assumed that an auxiliary operator must locally investigate all failures before any engine restarts are attempted.

Therefore, local plant operators must be dispatched to the diesel generator building for all diesel generator recovery actions. The control room operators or the control room foreman will contact an auxiliary operator by telephone or page soon after the diesel generator fails. After the auxiliary operator has been notified of the failure, the auxiliary operator will proceed to the diesel generator rooms to investigate the cause, reset engine trip relays, and begin local recovery efforts including manual restart attempts. It is estimated that the operator's response time for going to the diesel generator building from any of the normal duty locations is approximately 5 to 10 minutes after notification. This is expected to bound the time required, based on informal experience in walking from various plant areas to the diesel generator building. The auxiliary operators will be able to unlock controlled access doors since the key card is the identification badge, which is needed to enter the controlled areas.

The following distribution has been derived based on review of diesel generator failure and maintenance records, and on consultation with experts in maintenance and operation. It is used to model the response time for an auxiliary operator. It applies to the elapsed time from failure of the diesel generator until the operator begins local troubleshooting activities in the diesel generator room. This time includes initial failure detection time, delays for the control room to contact the operator and describe the problem, operator transit time to the diesel generator building, and possible additional delays due to communications problems or other considerations that could impede the operator's response.

Time for First Operator Response to Failed Diesel Generator (Includes Detection Time, Notification Time, and Transit Time)	
Response Time (minutes)	**Probability**
0 to 5	0.01
5 to 10	0.25
10 to 15	0.50
15 to 20	0.20
20 to 30	0.03
30 to 60	0.01

It is also expected that the in-plant foreman and the onsite maintenance technicians will respond to diesel generator failures that are not quickly corrected by the auxiliary operator. Depending on the status of equipment in other parts of the plant, additional qualified auxiliary operators may also be available to help with the recovery efforts. The participation of this normal complement of shift personnel has been considered in this recovery time distribution.

If both diesel generators for a Beaver Valley Unit fail, the operating and maintenance personnel would concentrate their initial recovery efforts on one of the diesels. A preliminary evaluation would be made to determine whether one of the diesels could be repaired more quickly than the others, and then that diesel would receive the most concentrated attention. For example, efforts would be made to restart a diesel generator that tripped spuriously before repairs were started on a diesel engine that sustained extensive mechanical damage. In this recovery model, it is assumed that the initial response team will concentrate its efforts almost exclusively on one diesel generator for approximately 20 minutes after the auxiliary operator reaches the building.

If the first diesel is not restored to operation after 20 minutes, it is expected that the response team will begin parallel efforts to recover the other failed unit. For example, the maintenance technicians could remain with the first diesel to begin component repairs or replacement while the operators turned their attention to troubleshooting and restart attempts on the other unit. As more support personnel respond to the site, the repairs of diesel generators can proceed in parallel and the recovery models can be substantially decoupled.

For the electric power recovery analysis, if both diesel generators have failed at a Beaver Valley Unit, recovery of only one is allowed during the first 30 minutes after initial operator response. Power can be restored from the diesel generators to one emergency AC bus in this interval. For periods longer than 30 minutes, the model permits recovery to be started on the second diesel generator and work is assumed to proceed on two diesel generators in parallel until power is restored. Thus, the minimum amount of time required to begin power recovery to all emergency AC buses by repairing failed diesel generators is more than 30 minutes after the diesel generators fail.

Integrated Diesel Generator Power Recovery Model

The integrated diesel generator power recovery model is as follows:

Single Diesel Generator Recovery

After a loss of offsite power, the emergency AC buses will be deenergized if both diesel generators at a Beaver Valley Unit fail due to a failure of their respective DC power or experience failure during the starting sequence or the subsequent operation. It is assumed for the analysis that DC power from the respective battery (1 or 2) is required for diesel generator recovery. Thus, recovery of only one diesel generator is assumed to be possible if DC power is available to only one diesel generator. The model for a single diesel generator recovery is:

$$\Phi_1(t+\tau) = \int [\varphi_{OR}(t)][\Phi_{DH}(\tau)]dt \qquad \text{(Eq. 1)}$$

where:

$\Phi_1(t + \tau)$ = cumulative frequency of power recovery from a single diesel generator when only one diesel is available for recovery.

$\varphi_{OR}(t)dt$ = frequency of auxiliary operator response to diesel generator room between t + dt after the failure of diesel generator power.

$\Phi_{DH}(\tau)$ = cumulative frequency of diesel generator hardware recovery within time (τ) after operator response.

This analysis is performed for conditions when only one diesel is available for recovery; that is, the other diesel has failed at t = 0 and cannot be recovered within 24 hours. For this analysis, approximately 20 percent of the single diesel unavailability is assumed to be attributed to preexisting maintenance scenarios. The 5th percentile model for the single diesel recovery reduces the cumulative frequency of recovery for one diesel by 20 percent. For the 95th percentile, however, a more optimistic view is taken and it is assumed that this fraction of unavailability is recoverable. This will include, for example, restoring the diesel to service after minor maintenance or testing. For the 50th percentile, it is assumed that the fraction of unavailability due to maintenance is recoverable after 2 hours.

The 5th percentile of the single recovery model represents a pessimistic model for operator response and delays the auxiliary operator's arrival time by 30 minutes. The 50th percentile of the model represents a delay of the operator's arrival by 10 minutes.

The 95th percentile bound represents a more optimistic model for operator response, and no delay in the auxiliary operator's arrival is included.

Figure 1 presents the complementary cumulative distribution for the diesel generator non-recovery that is derived for these bounding models. (That is, the 95th percentile represents the 5th percentile recovery model, and the 5th percentile represents the 95th percentile recovery, as discussed previously.)

One Out of Two Diesel Generator Recovery

If power can be recovered only from both diesel generators, successful recovery has been defined for this analysis as the restoration of power from at least one of the two diesel generators. This recovery model is characterized by the expression:

$$\Phi_{1/2}(t + \tau) = \Phi_1(t + \tau) + [1 - \Phi_1(t + \tau)][\Phi_1(t + \tau - 0.5)] \qquad \text{(Eq. 2)}$$

This model allows recovery of the first of the two diesel generators to begin when an auxiliary operator arrives at the diesel generator room. Recovery of the second diesel begins 30 minutes after the auxiliary operator arrives, and the repairs of both diesels are modeled as continuing in parallel thereafter.

Two bounding scenarios are applied as the 5th and 95th percentiles for the diesel generator recovery model.

For the 5th percentile bound, the single diesel generator recovery model (Eq. 1) is used. This model represents a pessimistic model for operator response, and it allows recovery of power from only one diesel generator. Parallel repairs of the second diesel generator are not considered. This bound accounts for possible unidentified dependencies in the recovery efforts for both diesel generators, which could couple the repair time distributions; for example, limited spare parts availability and limited support personnel availability.

For the 95th percentile bound, the dual diesel generator recovery model (Eq. 2) is used. The recovery of the second diesel begins 30 minutes after the operator arrives, and the repairs of both diesels are modeled as continuing in parallel thereafter. The 95th percentile bound, thus, represents a more optimistic assessment of operator response, and it includes a more realistic model for single and parallel diesel generator repairs. The 50th percentile is estimated from the 5th and 95th percentile curves.

Figure 2 presents the complementary cumulative distribution for the diesel generator non-recovery derived from these bounding models.

<u>EDG Recovery Time Window Based on Availability of 125V DC Power</u>

Although each diesel has two independent air-starting systems, each diesel generator requires a supply of 125V DC from its respective DC bus for generator field flashing and generator start and control. The effect of the unavailability of DC power on diesel generator recovery is accounted for in the integrated recovery model.

The available time for recovery is a function of both support system availability and Reactor Coolant System (RCS) thermal-hydraulics. Each diesel generator requires a supply of 125V DC power to start and operate. If, for example, a battery can last 12 hours after the loss of all onsite power (diesel generators), the auxiliary operators would have a time window of only 12 hours to recover the diesels. This is as long as the thermal-hydraulic window is longer than or equal to 12 hours. The thermal-hydraulic time window is a function of the availability of AFW and the leak rate from the reactor coolant pump (RCP) seals. For example, assuming AFW (the turbine-driven AFW pump) is available when and after onsite power is lost, then the time window for onsite power recovery and for the operator's response time to locally manually operate onsite breakers after DC power is lost is dependent on the leak rate from the RCP seals, which defines the time to core uncovery from this leak.

During the variable time window established by thermal-hydraulic considerations for diesel generator failure scenarios, the operators will be restoring power to emergency AC buses by either recovering one diesel generator or recovering power from the offsite grid previously described. The diesel generators are assumed in this analysis to be unrecoverable after depletion of the DC batteries (that is, after a duty cycle of 2.6 hours at Unit 1 and 3.5 hours at Unit 2), since DC power must be available to start the diesel. The restoration of offsite power, however, is assumed to continue after this duty cycle, but to add an additional 0.5-hour delay to the recovery. The addition of the 0.5-hour delay is to account for the contribution of manual operation of the breakers to offsite power recovery after the battery duty cycle.

Electric Power Recovery Model Assembly

The time-dependent calculations for the integrated electric power failure and recovery model are performed using the STADIC computer simulation program. The STADIC computer code, uses Monte Carlo simulation techniques to select a single random number for each variable based on the probability distributions provided as input.

The model computes the following:

- Conditional probability of onsite power system (diesel generator) failure in a mission time of 24 hours with failure to recover diesel generators or offsite electric power before core damage (designated by the variable QLP in the STADIC subroutine QDG)

- Conditional probability of onsite power system failure in a 24-hour period without including recovery (designated by the variable QTM in the STADIC subroutine QDG)

The ratio of QLP/QTM gives the electric power non-recovery factor. This model considers diesel generator failures after an LOSP initiating event.

The recovery of offsite power without onsite power available was assumed to be delayed for 0.5 hours, once the batteries have failed to allow time for making a decision about which breakers to close; for the control room supervisor to brief auxiliary operators; and for the auxiliary operators to manually close the breakers and to correct breaker malfunctions (or to choose alternate paths or a set of breakers). Since DC power is also required to recover the diesel generators, the cumulative non-recovery probability for the diesel generators was assumed to remain constant at the value calculated at the time the plant batteries fail when no offsite electric power is available. In conclusion, the recovery time available for the restoration of AC power from the diesel generators is limited either by the plant thermal-hydraulic time window or by the availability of the batteries.

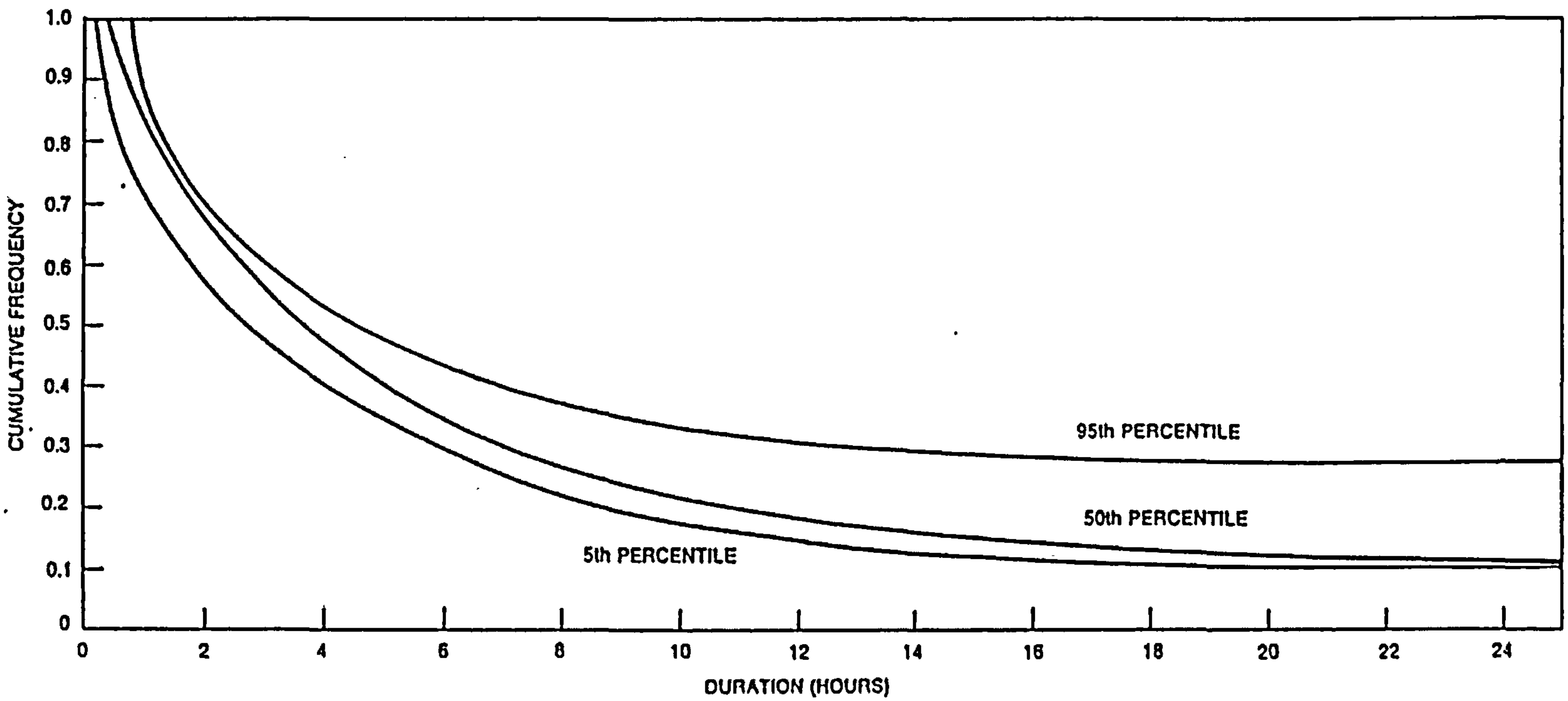


Figure 1. Non-Recovery of Single Diesel Generator

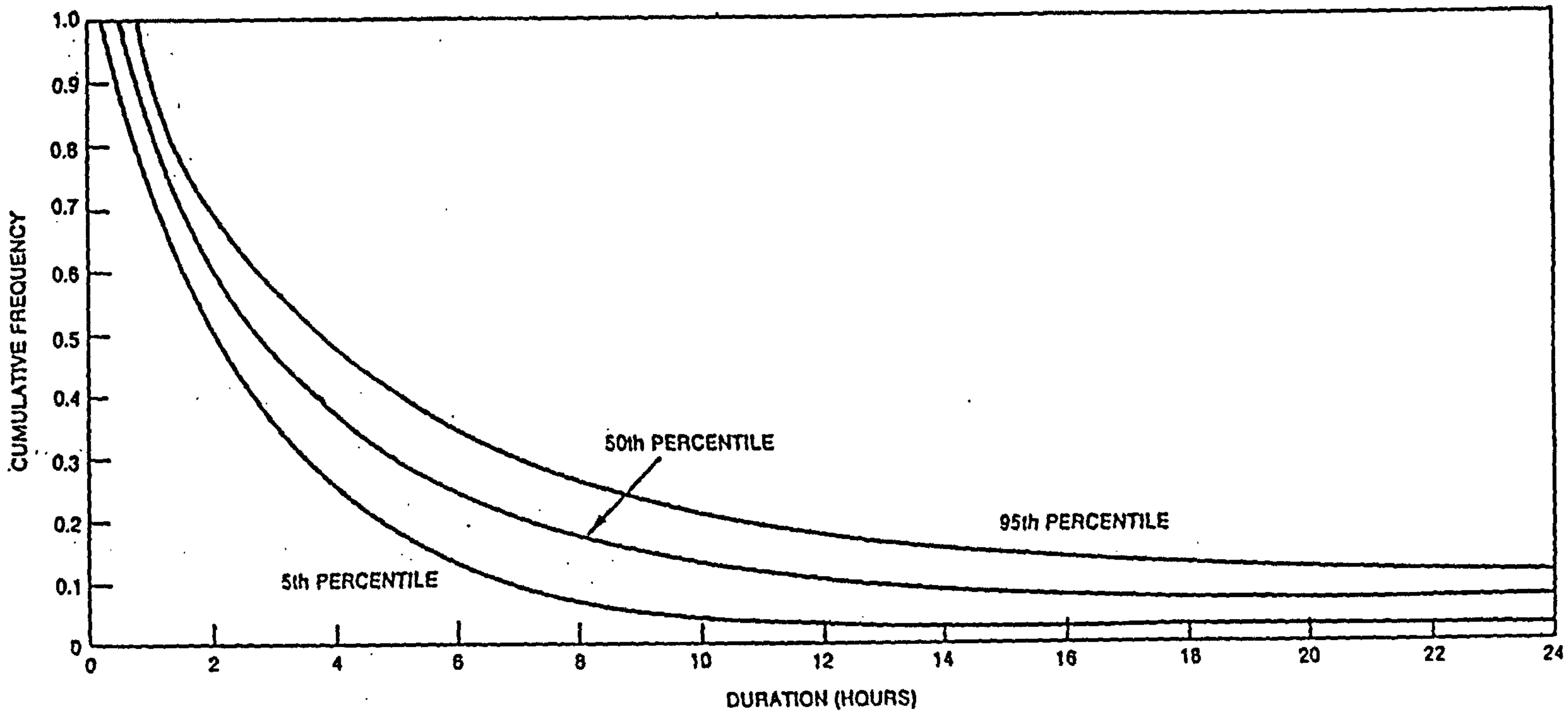


Figure 2. Non-Recovery of One Out of Two Diesel Generator